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San Juan Basin Action Plan

PURPOSE AND NEED TECHNICAL REPORT

for the
**Environmental Impact Statement
on Public Service Company of New Mexico's
Proposed New Mexico Generating Station
and Possible New Town**

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243
.N6
S265
1982
v.1
c.2

United States
Department
of the Interior

Bureau of Land Management
New Mexico State Office
Santa Fe, New Mexico

October 1982

Report 1 of 22

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United States Department of the Interior

BUREAU OF LAND MANAGEMENT
NEW MEXICO STATE OFFICE
P.O. BOX 1449
SANTA FE, NEW MEXICO 87501

IN REPLY REFER TO
NM30840EIS
1792.73(934A)

October 1982

Dear Interested Citizen:

Attached is one of twenty-two technical reports developed as a basis for writing the Environmental Impact Statement on Public Service Company of New Mexico's Proposed New Mexico Generating Station and Possible New Town (NMGS EIS). (A list of the technical reports is attached.)

These technical reports provide detailed information on the existing environment, methods used for the impact analysis, and related data supportive of the analysis and conclusions presented in the EIS. These reports should be retained for use with the Draft and Final EIS and other documents related to BLM's San Juan Basin Action Plan (SJBAP).

The Draft NMGS EIS will be filed with the Environmental Protection Agency and released for public review on November 30, 1982. Comments on the Draft EIS will be due by close of business February 7, 1983, at the BLM New Mexico State Office. Because of the large volume of material presented in the technical reports, the BLM is distributing these reports in advance of the Draft EIS to provide sufficient time for public review. The technical reports will be available for public review at the places indicated on the attached list. Copies will also be available from the BLM New Mexico State Office, U.S. Post Office and Federal Building, Santa Fe, for a copy fee.

Informational public meetings are scheduled for December 1982 to provide a public forum to clarify questions and concerns about the SJBAP proposals and the related environmental documents, which will all have been issued by that time. The meetings are scheduled as follows:

- December 14, Civic Center, Farmington, 3 to 9 PM
- December 14, Convention Center, Albuquerque, 3 to 9 PM
- December 15, Chapter House, Crownpoint, 3 to 9 PM
- December 16, Holiday Inn, Gallup, 3 to 9 PM
- December 16, Kachina Lodge, Taos, 3 to 9 PM

In addition, formal public hearings will be held in January 1983 to solicit public comments on the SJBAP Proposals. These meetings are scheduled as follows:

- January 10, Chapter House, Crownpoint, beginning at 1:00 PM
- January 12, Civic Center, Farmington, beginning at 9:00 AM
- January 14 (and 15th if necessary because of the number of registrants), Four Seasons Motor Lodge, Albuquerque, I-40 and Carlisle Blvd., beginning at 9:00 AM (each day)

Questions on the public meetings, hearings, and the technical reports themselves should be directed to:

Leslie M. Cone
NMGS Project Manager
BLM, New Mexico State Office
P.O. Box 1449
Santa Fe, NM 87501
(505) 988-6184   FTS 476-6184

Sincerely yours,

Charles W. Luscher

Charles W. Luscher
State Director, New Mexico

List of Technical Reports

1. Purpose and Need
2. Project Description
3. Alternatives to the Project
4. Site Alternatives
5. Permit Reconnaissance
6. Air Quality
7. Geologic Setting
8. Mineral Resources
9. Paleontology
10. Soils, Prime and Unique Farmlands
11. Hydrology
12. Water Quality
13. Vegetation
14. Wildlife and Aquatic Biology
15. Threatened and Endangered Species
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Copies of the reports are available for public review at the locations listed below. [Formal and informal cooperating agencies are denoted by an asterisk (*).]

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Montevideo Plaza
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OTHER ORGANIZATIONS

Public Service Company of New Mexico
Alvarado Square
P.O. Box 2268
Albuquerque, NM 87158
(505) 848-2700

Woodward-Clyde Consultants, Inc.
3 Embarcadero Center, Suite 700
San Francisco, California 94111
(415) 956-7070

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Aztec, NM 87401

Crownpoint Community Library
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Crownpoint, NM 87313

Cuba Public Library
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Cuba, NM 87027

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Farmington, NM 87401

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Crownpoint, NM 87313
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Bureau of Indian Affairs*
Navajo Area Office
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Window Rock, AZ 86515
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Bureau of Reclamation*
Upper Colorado Regional Office
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Salt Lake City, UT 84147
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Minerals Management Service*
South Central Region
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Albuquerque, NM 87102
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Minerals Management Service*
Resource Evaluation Office
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Farmington, NM 87401
(505) 327-7397 FTS 572-6254

National Park Service*
Southwest Regional Office
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Santa Fe, NM 87501
(505) 988-6375 FTS 476-6375

National Park Service*
Environmental Coordination Office
Pinon Building, 1220 St. Francis Drive
P.O. Box 728
Santa Fe, NM 87501
(505) 988-6681 FTS 476-6681

U.S. Fish and Wildlife Service*
Field Supervisor, Ecological Services
3530 Pan American Highway, Suite C
Albuquerque, NM 87107
(505) 766-3966 FTS 479-3966

U.S. Geological Survey (WRD)*
505 Marquette Avenue, Room 720
Albuquerque, NM 87101
(505) 766-2810 FTS 474-2817

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1201 Elm Street
Dallas, TX 75270
(214) 767-2716 FTS 729-2716

Navajo Tribe*
c/o Division of Resources
P.O. Box 308
Window Rock, AZ 86515
(602) 871-6592

Pueblo of Zia*
General Delivery
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(505) 867-3304

Soil Conservation Service*
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Aztec, NM 87410
(505) 334-9437

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Albuquerque, NM 87103
(505) 766-2657 FTS 474-2657

USDA, Forest Service*
717 Gold Avenue
Albuquerque, NM 87102
(505) 474-1676 FTS 474-1676

USDA, Forest Service*
District Ranger
Mt. Taylor Ranger District
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Grants, NM 87020
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4601 College Blvd.
Farmington, NM 87401

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Learning Resources Center
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PURPOSE AND NEED
TECHNICAL REPORT

for the
Environmental Impact Statement
on Public Service Company of New Mexico's
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and Possible New Town

Prepared by

Woodward-Clyde Consultants

for the

U.S. Department of the Interior
Bureau of Land Management

CONTENTS

Chapter | Page

1.0 INTRODUCTION 1-1

2.0 SUMMARY OF METHODS AND RESULTS 2-1

2.1 Scope of Analysis 2-1
2.2 Analysis Process 2-4
2.3 Findings 2-5

3.0 BACKGROUND: ELECTRIC UTILITY SYSTEM PLANNING 3-1

3.1 Electric Power Needs and Supplies 3-1
3.2 Electric Supply Planning Issues 3-7
3.3 Supply Planning Process 3-14

4.0 PNM'S SUPPLY PLANNING PROCESS 4-1

5.0 STATEMENT OF PURPOSE 5-1

5.1 Summary Statement of Purpose 5-1
5.2 PNM's Statements of Purpose 5-1
5.3 Review of Statement of Purpose 5-6

6.0 ASSESSMENT OF NEED

6.1 PNM's Assessment of Need
6.2 Review of Assessment of Need

Appendix A: Need for Power Support Studies and Documentation

Appendix B: Detailed Analysis of PNM's Assessment of Need

REFERENCES

PREPARERS

TABLES

Table		Page
2-1	Meetings Held Concerning Purpose and Need	2-3
6-1	Summary of PNM Forecast Scenarios for Total Electrical Energy and Existing and Planned Supply Capacity, Excluding NMGS	6-4
6-2	Summary of PNM Forecast Scenarios for Total Peak Electrical Requirements and Existing and Planned Supply Capacity, Excluding NMGS	6-5
6-3	Summary of PNM Historical Electrical Requirements	6-10
6-4	Comparison of Historical and Forecast Growth Rates of Electrical Use	6-11
6-5	Summary of Input Variables for PNM Forecasting Models	6-14

FIGURES

3-1	Hourly Need for Electricity, Wednesday, April 9, 1980	3-2
3-2	Peak Need for Electricity, by Month, for 1980	3-3
6-1	Summary of PNM Forecast Scenarios (Total Requirements)	6-6
6-2	Summary of PNM Forecast Scenarios and Planned Capacity Additions (Total Requirements)	6-7
6-3	Summary of PNM Forecast Scenarios (Peak Requirements)	6-8
6-4	Summary of PNM Forecast Scenarios and Planned Capacity Additions (Peak Requirements)	6-9

1.0
INTRODUCTION

This technical report presents supporting analysis and discussions related to purpose and need as described in Chapter 1 of the New Mexico Generating Station (NMGS) Environmental Impact Statement (EIS). In accordance with the regulations of the Council on Environmental Quality [1] implementing the National Environmental Policy Act of 1969 (NEPA), the Bureau of Land Management (BLM), acting as the federal lead agency for the preparation of the NMGS EIS has a responsibility to "briefly specify the underlying purpose and need to which the agency is responding in proposing the alternatives including the proposed action." In order to carry out this responsibility and to provide a basis for assessment of alternatives to NMGS including the no-action alternative, the BLM has reviewed and assessed the reasonableness of Public Service Company of New Mexico's (PNM's) statement of purpose and assessment of need for NMGS.

This report is organized as follows: Section 2.0 presents a summary of methods and results, Section 3.0 provides background information on electric utility system planning practices, Section 4.0 reviews PNM's supply planning process, Section 5.0 reviews PNM's statement of purpose, and Section 6.0 reviews PNM's assessment of need. Supporting material is included in two appendices.

2.0
SUMMARY OF METHODS AND RESULTS

2.1 SCOPE OF ANALYSIS

In discharging its responsibilities concerning purpose and need, the BLM has examined the scope and authority of its statutory review responsibilities regarding this issue in the context of the NEPA review process. The BLM is not among the numerous federal and state agencies which have legislated mandates and responsibilities regarding the regulation of electric utility business. In response to public comment [2], the BLM has noted [3] that regulatory responsibility for determining whether there is a need for NMGS rests with the New Mexico Public Service Commission (NMPSC), in accordance with New Mexico's Public Utility Act [4]. This responsibility of the NMPSC has been directly confirmed by the NMPSC [5]. Under the Public Utility Act, utilities wishing to begin construction of a power plant are required to obtain a Certificate of Public Convenience and Necessity from the NMPSC. As part of the certificating proceedings, the NMPSC reviews the need for additional power generating facilities.

However, in order to ensure that reasonable alternatives to NMGS are identified and that these alternatives, including the no-action alternative, are realistically assessed, the BLM has reviewed PNM's statement of purpose and need for NMGS. Specifically, the roles of the BLM with regard to purpose and need are: (1) to ensure that PNM is pursuing a reasonable purpose in attempting to obtain environmental approval at this time for NMGS, and (2) to ensure that there is sufficient likelihood that NMGS will be needed so that environmental review is justified at this time for issuance of rights-of-way (ROW) permits for electric transmission lines.

Because of the particular public concerns, expressed during and subsequent to the scoping process, about the purpose and need for NMGS [2,6,7], the BLM has made a concerted effort to examine the issues of purpose and need. The assessment has included review of documents provided by PNM, interviews with PNM technical staff and management, review of documents provided by other interested parties, meetings with other interested parties, and review of testimony and other materials submitted in recent NMPSC cases. Independent mathematical checks and calculations were also conducted. The documents related to purpose and need provided to the BLM by PNM and other sources are referenced in the appropriate sections of this technical report. Meetings held with PNM staff, government agencies, and other parties are summarized in Table 2-1. Further evaluation of the need for NMGS would be undertaken in public view at a later date by the NMPSC in certificating proceedings.

Within this context the BLM has focused attention on the following questions:

- With regard to PNM's purpose for seeking environmental review of NMGS:
  - -- Is this purpose in accord with PNM's statutory responsibilities and corporate objectives?
  - -- Is this purpose in accord with accepted practice within the electric utility industry?

Table 2-1. MEETINGS HELD CONCERNING PURPOSE AND NEED

Date	Group(s) Involved
April 1, 1981	Committee on Coal
May 21, 1981	PNM
July 7, 1981	California Energy Commission
July 8, 1981	California Public Utilities Commission
July 31, 1981	PNM
July 31, 1981	New Mexico Public Service Commission
September 29, 1981	Sierra Club; Committee on Coal
September 30, 1981	New Mexico Attorney General's Office
October 1-2, 1981	PNM
April 6-7, 1982	PNM
April 14, 1982	New Mexico Public Service Commission
April 22, 1982	David Marcus (telephone conversation)
May 4, 1982	New Mexico Solar Energy Association
May 5, 1982	New Mexico Bureau of Business and Economic Research
May 5, 1982	Dr. Alfred Parker, University of New Mexico
May 6, 1982	New Mexico Solar Energy Institute

  - -- Is this purpose consistent with other public statements of position by PNM?

- With regard to PNM's assessment of the need for NMGS:

  - -- Was the assessment conducted using methods that are generally used within the utility industry?

  - -- Were the assessment methods reasonably applied to the situation and environment under which PNM operates?

  - -- Are the assessment results obtained consistent with other public statements on need by PNM?

2.2 ANALYSIS PROCESS

The BLM's analysis of purpose and need was conducted in four steps:

- Review PNM's statement of purpose
- Review PNM's methodology for need assessment
- Review PNM's input data assumptions
- Review other assessments of need

These steps are discussed below.

Review PNM's Statement of Purpose

Documents provided by PNM presenting its purpose for the NMGS project were reviewed. This purpose was compared with accepted practice within the electric utility industry and with other public statements of position by PNM. Based on this comparison, an assessment was made of the reasonableness of the purpose of NMGS. The review of the statement of purpose is presented in Section 5.0.

Review PNM's Methodology for Need Assessment

Documents provided by PNM presenting its methodology for need assessment were reviewed. This methodology was further clarified through meetings, telephone conversations, and exchanges of letters with PNM staff. The need assessment methodology was compared with accepted practice within the electric utility industry. Based on this comparison, an assessment was made of the methodology used by PNM. The review of PNM's methodology is presented in Section 6.0 and supporting material is included in Appendices A and B.

Review PNM's Input Data Assumptions

These data assumptions were compared with other information sources. Section 6.0 and Appendix B provide more details.

Review Other Assessments of Need

PNM's assessment of need was compared with other assessments. Non-PNM sources that were contacted are summarized in Table 2-1. Further details of the comparison are in Section 6.0 and Appendix B.

2.3 FINDINGS

Based on the review of PNM's statement of purpose for NMGS, as detailed in Section 5.0, we find:

- The purpose is in accord with PNM's statutory responsibilities and corporate objectives.
- The purpose is in accord with accepted practice within the electric utility industry.
- The purpose is consistent with other public statements of position by PNM.

Based on the review of PNM's assessment of need for NMGS, as detailed in Section 6.0 and Appendix B, we find:

- The assessment of need was conducted using methods that are generally used within the utility industry.
- The assessment methods were reasonably applied to the situation and environment under which PNM operates; exceptions of a technical nature, while not affecting the overall results of the assessment, have been noted in Section B.3.2 of Appendix B.
- The assessment results obtained are at variance with certain other public statements on need by PNM, however, the reasons for these variances have been satisfactorily explained by PNM.

3.0
BACKGROUND: ELECTRIC UTILITY SYSTEM PLANNING

This section summarizes the characteristics of electric power needs and supplies, and also reviews the process used by electric utilities to plan for supplying future needs for electric power. This discussion is provided as background, particularly for readers who are not familiar with electric power planning, to assist in understanding the assessment of purpose and need in subsequent sections.

3.1 ELECTRIC POWER NEEDS AND SUPPLIES

New Mexico's need for electric power varies from hour-to-hour through the day and also from month-to-month through the year. This is illustrated by the load curves shown in Figures 3-1 and 3-2. Figure 3-1 shows that on April 9, 1980, the hourly need for electricity by the customers of Public Service Company of New Mexico ranged from a low of 337 megawatts in the period after midnight to a high of 537 megawatts in the early evening. Similarly, Figure 3-2 shows a substantial variation in need for electric power over the four seasons of 1980.

By straightforward calculations, it can be shown that the average need for electricity over the April 9, 1980, period shown in Figure 3-1 was 444 megawatts. That is, if exactly 444 megawatts had been used every hour of the day, then the same total amount of electricity would have been used on April 9, 1980, as was used by the actual

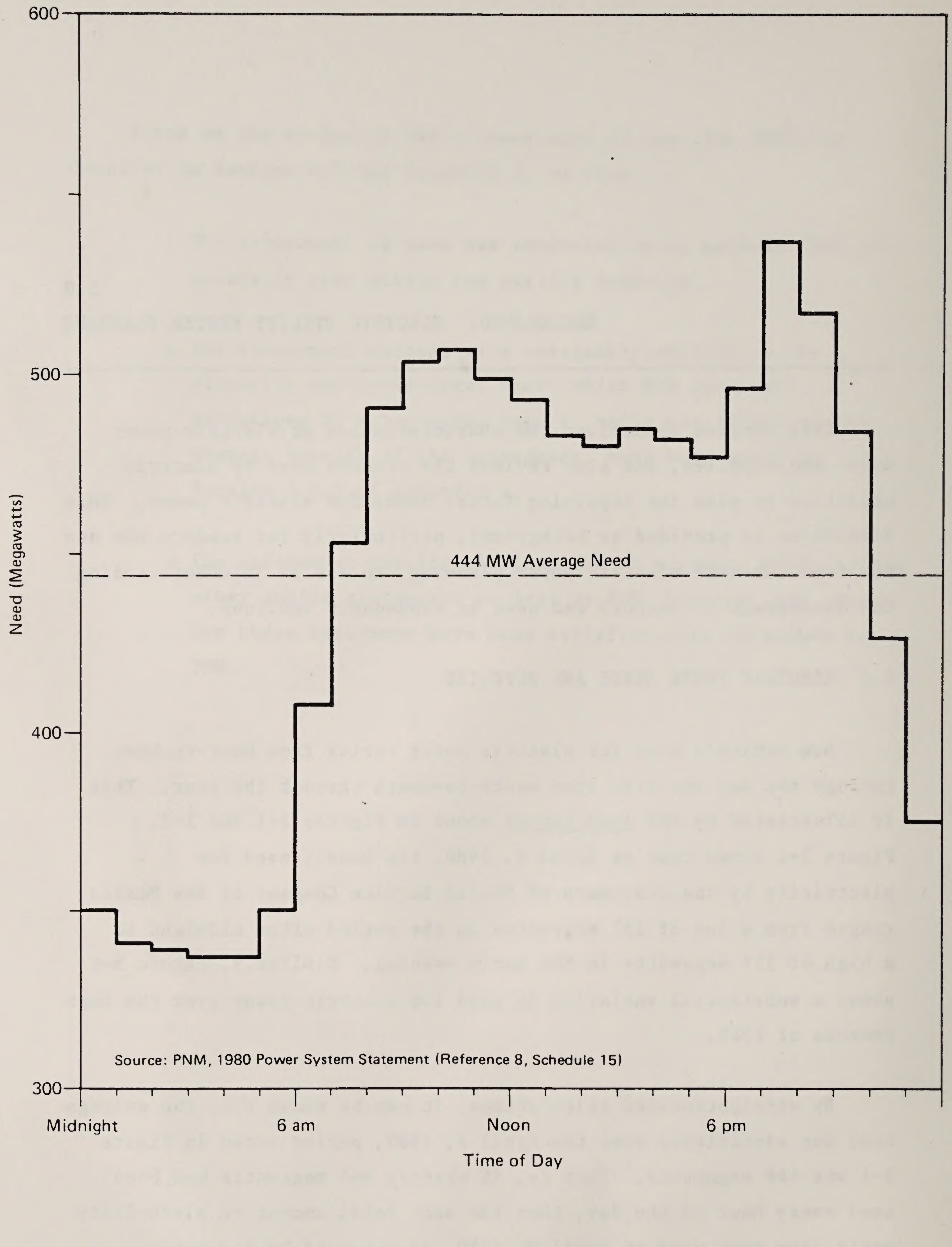
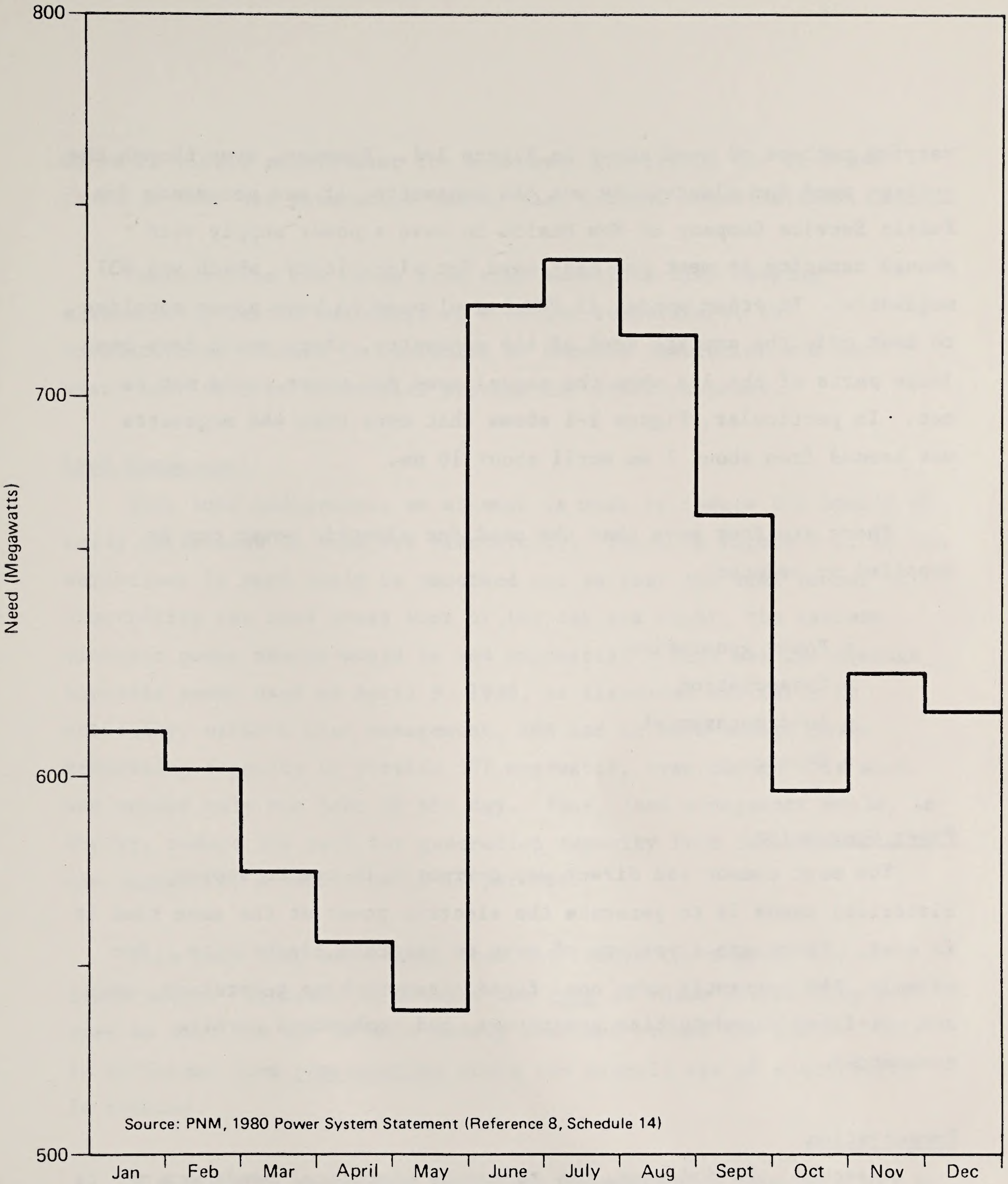


Figure 3-1. HOURLY NEED FOR ELECTRICITY, WEDNESDAY, APRIL 9, 1980



Source: PNM, 1980 Power System Statement (Reference 8, Schedule 14)

Figure 3-2. PEAK NEED FOR ELECTRICITY, BY MONTH, FOR 1980

varying pattern of need shown in Figure 3-1. However, even though the average need for electricity was 444 megawatts, it was necessary for Public Service Company of New Mexico to have a power supply with enough capacity to meet the peak need for electricity, which was 537 megawatts. In other words, if PNM had planned to have power supplies to meet only the average need of 444 megawatts, there would have been large parts of the day when the actual need for power could not be met. In particular, Figure 3-1 shows that more than 444 megawatts was needed from about 7 am until about 10 pm.

There are four ways that the need for electric power can be supplied or reduced:

- Power generation
- Conservation
- Load management
- Storage

Power Generation

The most common and direct way currently in use to supply electrical needs is to generate the electric power at the same time it is used. There are a variety of ways to generate electricity. For example, PNM currently uses coal-fired steam-turbine generators, gas- and oil-fired steam-turbine generators, and combustion turbine generators.

Conservation

A second, and indirect, way to ensure electrical needs are met is through conservation. This method decreases demand in lieu of increasing supply. With this approach, the amount of electricity used by each individual home, business, and factory is reduced so that even as the total number of homes, businesses, and factories increases there is little requirement for new power generation (or at least there is less new generation needed than without conservation).

Conservation can range from simple actions like keeping electrically heated buildings at a cooler temperature, to sophisticated schemes in factories to improve insulation and use waste heat from an industrial process for other purposes.

Load Management

With load management, an attempt is made to reduce the hourly or daily variations in need for electricity. Thus, in Figure 3-1, if the variations in need could be smoothed out so that the same amount of electricity was used every hour of the day and night, the maximum electric power needed would be 444 megawatts. (This was the average electric power used on April 9, 1980, as discussed earlier.) In actuality, without load management, PNM had to have enough power generating capacity to provide 537 megawatts, even though this much was needed only one hour of the day. Thus, load management could, in theory, reduce the need for generation capacity from 537 megawatts to 444 megawatts, a reduction of 17 percent.

Note that load management does not reduce the overall use of electricity. Instead, it changes the time at which electricity is used so that the use is more nearly constant around the clock. This is different from conservation where the overall use of electricity is reduced.

A difficulty associated with load management is finding a way to get electricity users to "smooth out" their consumption of electricity. In the load curve shown in Figure 3-1, it is likely that electricity use is low late at night because people are asleep.

One way to get people to change their pattern of electricity use is to introduce time-of-day pricing (also called time-of-use, peak load, or peak responsibility pricing). Under this system, electricity would be cheaper during certain times of the day than at other times. (This is similar to what the telephone company does with telephone calls.) This might lead people to shift their use from times when electricity costs more to times when it is cheaper.

If time-of-day pricing were used it would be necessary to have electric meters that could record the time at which electricity was used as well as the amount used. These meters are currently more expensive than conventional electric meters. In addition, electricity use might be less convenient or more expensive for consumers, since they would either have to pay more for electricity during periods of peak demand or find a way to shift their use to other times.

Storage

With storage, a utility generates electric power at a steady rate approximately equal to the average need and stores the extra power generated during the period when the need is less than average. This power is then supplied to customers when the need is above average. With this approach, as with load management, it is only necessary to have enough electric power generators to meet the average need, rather than the peak need.

Use of storage can be more convenient for customers than use of load management since the customers can continue to use differing amounts of electricity over the day and night. However, the available ways of storing large quantities of electricity are expensive. These include such approaches as pumped-storage hydroelectric plants and compressed air energy storage facilities. In many cases it is less expensive to supply peak electricity requirements with new generators than it is to build facilities to store energy. For example, if a pumped-storage hydroelectric plant is used, a combination pump/hydroelectric generator is used in conjunction with some type of water reservoir located at a higher elevation than the pump/generator. During times when the need for electricity is low, electrical power from other generators is used to pump water up into the reservoir. During periods of peak electrical need, this water is allowed to run down through the generator and produce electricity. This type of storage facility requires that a water reservoir be constructed as well as the combination pump/generator. In some cases, electricity can be generated less expensively by just building an additional generator. Also, with the pumped-storage system, some energy is lost due to friction and other effects during the pumping and generating cycle.

3.2 ELECTRIC SUPPLY PLANNING ISSUES

The preceding section discussed the characteristics of electrical needs and ways of supplying these needs. This section discusses the major issues that electric utilities consider when planning for future changes in their electric supplies. There are four major issues concerning a utility's ability to reliably and economically provide for future electric power needs that the utility must consider if it is to effectively meet future electrical needs:

- Uncertainties in forecasting electrical needs
- Over- and under-capacity costs
- Supply mix
- Reliability and reserve margin.

Each of these will be reviewed in this section, and then the methods used by utilities to plan for future methods of supplying electrical needs will be discussed in the next section.

Uncertainties in Forecasting Electrical Needs

A large electric power facility takes several years to build, and before construction can start it is necessary to decide on a site for the plant and obtain required regulatory approvals. The entire process can take a decade or more to complete. It is not possible to forecast for certain what the need for electricity will be that far in the future. This is because there are many factors which influence electricity needs that can change substantially over that period of time in ways that cannot be fully predicted. For example, use of refrigerative air conditioning may increase or the fraction of new homes that have electrical heat, rather than gas, may change. Also, the rate at which new residents move into the area may change. The extent and effect of conservation measures may change. The rate at which energy-intensive industry develops may also change substantially over a period of several years.

Although electrical utilities attempt to forecast these developments, there is substantial uncertainty in these forecasts. Generally, a utility will address these uncertainties by preparing several different forecasts of electrical needs which cover the range of possible future developments that they believe have a significant likelihood of occurring. Each of these forecasts is based on a different set of assumptions about future trends in the factors (such as air conditioning, electrical heat, conservation, industrial growth and so forth) that influence the need for electrical power. (Forecasting specialists refer to each set of assumptions as a scenario.)

Over- and Under-Capacity Costs

The economically preferable schedule and size for a new power plant or other way of providing for future power needs depend on the future need for power. This is because it can be costly to have either more power generation capacity than is needed (referred to as over-capacity), or less capacity than is needed (referred to as under-capacity). The costs of these two situations will now be discussed further.

If a utility has less electrical generating capacity than it needs (under-capacity), a variety of costs can occur. In an extreme case, the utility may not be able to provide the needed power in any way. This can lead to curtailments of use by customers or brownouts. These are inconvenient to customers, and can have an economic impact on businesses or industries that require electrical power for their operations. In less extreme cases, a utility can avoid curtailments by purchasing electrical power from other utilities. However, there is a risk that this power will not always be available since the other utilities may need it for their own customers. In addition, the other utilities may charge high prices for the power, which will then have to be paid by the customers of the utility which does not have sufficient generating capacity.

If a utility has more electrical generating capacity than it needs (over-capacity), the cost of each unit of energy generated may be higher than otherwise. This is because many of the costs of a power plant are the same regardless of the amount of power it generates. With fewer units of electrical energy being generated, these fixed costs must still be paid, and the cost per unit of electricity will be higher. This effect is somewhat counterbalanced by the fact that less fuel will be used if less electrical energy is generated. However, in many cases the overall effect is for each unit of electrical energy to be more expensive.

The situation is analogous to driving an automobile. There are fixed costs, like insurance and loan payments, that are the same regardless of how many miles per year the auto is driven. Thus, if the auto is driven fewer miles in a year, the cost per mile for these fixed costs will be higher. Of course, fuel and maintenance costs will be lower if the auto is driven less. However, the overall effect is often that an auto that is driven more miles per year will have a lower cost per mile. Similarly, a power plant that produces more units of electrical energy per year will generally have a lower cost per unit.

Supply Mix

A utility must also consider what is the preferable combination of methods for meeting or reducing its future electrical needs. Section 3.1 noted that there are four methods: Power generation, conservation, load management, and storage. Often, the economically and environmentally preferable way of supplying electrical needs involves a combination, or mix, of these different approaches. In addition, the specific way that any one of the approaches is utilized can significantly affect its attractiveness. This is because of the hourly and seasonal variations in power needs which were reviewed in Section 3.1.

To see the reason for this, first consider the option of meeting future electrical needs by building new power generation facilities. As noted above, it is preferable not to have either over- or under-capacity. However, an examination of the need curves in Figure 3-1 and 3-2 shows that it is not possible to avoid some over-capacity when the entire generation capacity of the utility is considered. This is because at certain times of the day (or seasons of the year) the power need is higher than at others. The utility must have enough generating capacity to meet the peak need, but for much of the day (or of the year) the need is less than this peak, and hence some of the generating capacity is not needed. Thus, overall, the utility must have over-capacity in order to be able to meet the peak need.

However, the utility can reduce the cost of this over-capacity by having a mix of different types of power generating facilities. This is because the amount of fixed costs relative to costs that occur only if power is generated differ for different kinds of power generating facilities. For example, a gas-turbine or diesel-engine generating plant has relatively low fixed costs but uses a substantial amount of relatively expensive fuel when it generates electric power. On the other hand, a large nuclear or coal-fired power plant has larger fixed costs relative to the cost of fuel for generation.

When the overall costs are calculated, it turns out that for many utilities if a power plant is to be used for only a small fraction of the time it is most economical to use a gas-turbine or diesel-engine generator. However, if the plant is to be used for a large fraction of the time, a nuclear or coal-fired plant is most economical.

Thus, in order to meet the varying need for electricity, utilities typically have several types of generators. There are certain plants, often nuclear or coal-fired, that are operated around-the-clock, twenty-four hours a day. These are the types of plants that are most economical when operated as much as possible. (Utility engineers refer to these as base load plants.) During periods when the need is higher, other types of plants, such as gas-turbine and diesel-engine generators, are operated. (These are referred to as peaking plants.)

This combination of plants provides for the overall, varying need more economically than if only one type of plant were used. However, deciding on the specific mix of plants to meet future electrical needs is more complicated than a straightforward economic calculation of the least costly mix of power plant types. This is because of uncertainties about future costs, regulations, and public acceptance. The following two examples illustrate these issues.

In the early 1970s, environmental regulations discouraged the use of coal-fired power plants because of the air quality difficulties associated with them. Some utilities concluded that oil-fired power plants were preferable as base load facilities. However, the economics and regulatory situation changed substantially following the oil embargo in 1973. Regulations now do not permit use of oil as a fuel in most new base load power plants, and even were it allowed, it has become much more expensive to use oil. Utilities planning their future power plants need to consider the possibility of similar types of changes occurring in the future.

Another example concerns nuclear power plants. Calculations show that for many utilities nuclear power plants would be the most economical base load plants, if they could be constructed according to the planned schedule. However, there are uncertainties about future regulatory and public attitudes toward such plants. These uncertainties pose risks of undesirable costs which many utilities believe are not acceptable.

The review above shows that selecting a supply mix requires careful analysis. Use of conservation and load management requires that additional issues be considered. As an example, consider conservation. To be specific, consider a conservation approach where conventional electrical heating is replaced by a system of solar heating and better insulation, with electrical heating as a back-up. Whether this conservation approach is less expensive will depend on the cost of the solar heating system and insulation. Also, the reduction in electrical need resulting from the conservation can only be forecast with accuracy if there is analysis of factors like local climate variations and efficiency of the solar systems being used.

Reliability and Reserve Margin

Utilities normally maintain somewhat more capacity to supply electric power than their expected peak need. The extra supply capacity is referred to as the reserve margin. There are two principal reasons for maintaining this extra capacity: First, so that if there is an unexpected mechanical problem which requires that a power plant be shut down for repairs, the utility can supply the electrical power need with the reserve margin. Second, if unusual conditions occur which lead to a higher than expected need for power, such as very hot or very cold weather, the reserve margin can be used to supply the need.

The desirable reserve margin depends on how great a risk the utility is willing to run of not being able to supply its customers' electrical power needs. Generally utilities attempt to have enough reserve margin to keep the likelihood of not being able to meet the need very low.

The complexities of reserve margin planning are indicated by the following discussion provided by PNM [8]:

> The Four Corners Interconnection Principles require in Sections 1.2 and 1.3 that all participants maintain a forecast capacity resource margin at least equal to 15 percent of the estimated peak demand for each month of the 3-year forecast period. The participation agreement for the Arizona Nuclear Power Project (ANPP) contains these same principles in Appendix J. WSCC's [Western Systems Coordinating Council] power supply design criteria recommends that member systems should meet or exceed at least one of the following criteria for installed and planned generating capacity reserves:
>
> 1. Greater of 15 percent of the monthly firm peak load demand, assuming the member has no hydro units, or the largest system hazard plus 5 percent of the peak load.
>
> 2. Loss of the two largest system hazards, where the hazard is either a generating unit or a transmission line.

3. The system reliability criteria is based on either a probability of loss of load of one day in 10 years, or a 90 percent probability of meeting all loads during the year.

The NMPP Agreement in Article 10 requires each member to maintain spinning reserve capacity and that the pool total be at least equal to the pool's combined largest single hazard.

PNM has determined from its operating experience that it can usually meet its capacity requirements with a planned capacity equal to the projected annual peak plus a reserve margin of the larger of (1) the largest single generating hazard, or (2) 20 percent of the annual peak demand. Detailed generation cost modeling indicates that PNM's optimum economic reserve margin for 1982 through 1989 is as high as 31 percent of load. It is reasonable to expect this trend (i.e., reserve margins significantly above 20 percent) to continue through the 1990s.

3.3 SUPPLY PLANNING PROCESS

The characteristics reviewed in the last two sections have led to development of a particular planning process used by many utilities when they plan for changes in their electric power supply. Before discussing this process, the characteristics considered in the last two sections will be briefly summarized.

First, the electrical power needs of a utility's customers vary from hour-to-hour and from season to season. Also, there are uncertainties about the future which make it impossible to be completely accurate in forecasting electrical power needs for several years in advance (which is how far in advance power supply alternatives must be planned).

Utilities have a variety of ways available for meeting or reducing future electrical needs, including power generation, conservation, load management, and storage. Because of cost considerations, as well as uncertainties about factors such as future fuel costs and regulations, it is common practice to use a mix, or combination, of supply sources or other methods to provide for the electrical power needs.

Utilities generally handle these complexities and uncertainties with an iterative process that allows them to continually update their plans for ensuring that future electrical needs are met as conditions change. In order to maintain the ability to make modifications as conditions change, a utility will typically be simultaneously gathering information on, and taking action to be able to utilize, a variety of different supply sources. The utility will only make a firm commitment to use a particular supply when its forecasts of future needs predict that the need might not be supplied if action is not taken at this time.

The starting point for the iterative planning process is the utility's forecast of its customers' future need for electricity. Most medium to large size utilities use computer modeling methods as part of this forecasting process. Typically, historical data and information from local builders and developers, as well as government agencies, will serve as inputs to the forecast. Computer methods, such as econometric and end-use forecasting, will be used to process the historical data and other information and produce a forecast. As discussed earlier, there are substantial uncertainties about future events that may influence the future need for power. Thus, a number of different forecasts are made to estimate how these uncertainties could affect the need for power. Most utilities regularly update their forecasts of future power needs, often on an annual basis with minor modifications at more frequent intervals.

In parallel with the need forecasting, utilities will usually be collecting and updating information on the economic, environmental, and regulatory aspects of a wide range of different options for ensuring that electrical power needs are met. This information is collected from a variety of sources, such as the U.S. Department of Energy, the Electric Power Research Institute, and other research organizations. Utilities often supplement the information with studies of their own that examine aspects of power supply that are unique to their situation. The information on potential supply sources is updated on a regular basis.

The need forecasts and the supply information are combined to identify attractive supply alternatives. This often is done with the aid of detailed computer planning tools. These help to establish preferable schedules for starting site selection studies, licensing, and construction of any new facilities that may be needed.

As it gets closer to the time when the utility's planning studies indicate a new facility may be needed, the utility will usually establish a project team to study one or more supply options that look particularly attractive. If these options involve construction of a new facility, such as a power plant, a site selection study will be conducted, and preliminary engineering studies will be carried out. Following these, if the supply option still seems attractive, environmental studies and other licensing activities will be completed. Also, arrangements will be made to finance the facility, including possible participation by other utilities. An architect/ engineer will be selected.

While these activities are going on, the need forecasts will be periodically updated. This may lead to changes in the proposed schedule for constructing the facility. In many cases the schedule will "slip", or be lengthened. This is because in the early stages of a supply project it is usual to conduct planning based on a relatively high need forecast. This is done because it is relatively easy and inexpensive to slip a project schedule during the early part of the project while it may be difficult and expensive to speed-up the schedule. Thus, a high forecast is used as a basis for planning so that if need should grow more rapidly than expected, the new supply facility can be completed in time to supply the need.

Another approach would be to use a more probable need forecast as a basis for supply scheduling, and then simply not supply a high need if it should develop. The usual view in the electric utility industry is that this approach carries social and economic risks that are not acceptable [10]. PNM states that it may be illegal for a utility to make a decision not to supply a need in its service territory [11].

If the periodically updated need forecasts continue to indicate a need for a supply facility and both the required regulatory approvals and financing are obtained, the new supply facility will be built. However, even during construction, most utilities retain flexibility to modify the facility to meet changing conditions. For example, a large coal-fired power plant typically consists of two or more separate generating units. Usually these will be built in sequence as the power need grows. If the need grows more slowly than expected, the schedule for construction of each unit can be slowed down. Also, if a more desirable supply alternative becomes available, some of the initially planned units may never be built.

The presentation above has reviewed the planning process that utilities follow to select and develop a new power supply alternative. Of course, the level of effort and effectiveness of the planning process differs from utility to utility. However, the general approach outlined above is followed by most utilities.

4.0

PNM'S SUPPLY PLANNING PROCESS

This section reviews PNM's supply planning process. This review is based on examination of a variety of memoranda and other documents which PNM provided in response to requests for information. In addition, we have met with PNM technical staff to clarify the written information provided. PNM has prepared a document titled "Need for Power Support Studies and Documentation" which discusses certain aspects of PNM's planning process. This document is included as Appendix A to this technical report.

PNM states [12] that its planning considers three major issues: demand for power, supply, and finance. The integration of these issues is accomplished through the "Integrated Planning Loop", which consists of a series of computerized models. The primary models are concerned with forecasting future power needs, system planning, and financial planning. Since financial planning is outside the area of concern for the NMGS EIS, the discussion below will consider power need forecasting and system planning. PNM has explained its approach to these areas during the recent New Mexico Public Service Commission Case 1577, and the record of this case can be consulted for further details [13,14].

Forecasting Future Power Needs

PNM prepares an official forecast of the future electrical needs

5.0
STATEMENT OF PURPOSE

5.1 SUMMARY STATEMENT OF PURPOSE

The purpose of the NMGS project is to provide PNM with sufficient information to assess the benefits and risks of developing a coal-fired generating station, including the proposed project's impact on the human and natural environments. Based on current electric need forecasts, PNM anticipates that additional baseload generating capability will be required between 1990 and 2000, with one 500-MW generating unit needed possibly as early as May 1990. PNM views coal as the best available option for meeting part of the electrical needs of the 1990s.

5.2 PNM's STATEMENTS OF PURPOSE

PNM has submitted the following statement describing the purpose of NMGS [18]:

1. STATEMENT OF PURPOSE

   The purpose of this phase of the New Mexico Generating Station (NMGS) Project is to provide the management of the Public Service Company of New Mexico (PNM) with sufficient information to assess the benefits and risks of developing a coal-fired generating station. This risk and benefit analysis will be evaluated against a full range of options to meet the electrical energy needs of PNM's customers in the

1990s and beyond. Among the options considered by PNM are nuclear, geothermal, solar, hydro, conservation, and others. In order to make the best decision, PNM management requires information related to the feasibility and availability of such coal-related resources as land, water, and fuel. Additionally, PNM management requires information regarding the suitability of the proposed project's impact on the human and natural environments in accordance with the NEPA process.

As set forth in the July 10, 1981, letter from PNM to BLM, the proposed project consists of a coal-fired generating station with up to four 500-MW units. The units will be placed in service in the 1990s, with the first possibly as early as May 1990. Associated with the generating station are two 500-kV transmission lines to Albuquerque, a 500-kV tie to the Four Corners-Ambrosia 500-kV lines, and two water pipelines from San Juan River to the generating station.

2. BACKGROUND

Planning and constructing new power generation facilities is a complex and dynamic process. Multiple objectives must be satisfied within the limits of technological and economic feasibility. The chief planning objective is to match the supply of power with the customer's demand.

Given the omnipresent uncertainty of the future and the long time period, often in excess of ten years, that it takes to plan and construct a facility, additional complexity is added. The human, financial, and physical resources committed to such planning are enormous.

PNM's long range planning program is conducted pursuant to the New Mexico Public Utility Act and regulation by the N.M.P.S.C. The company's planning for future generation needs is consistent with its corporate mission to provide adequate and reliable electric service at the lowest reasonable cost to the ratepayer while providing a reasonable return to PNM investors.

To accomplish this mission, PNM employs state-of-the-art econometric modeling programs and forecasting techniques. The data deriving from those tools are incorporated into studies which indicate a range of future load growth. The impact of the increased energy prices, natural gas deregulation, energy and demand conservation, solar energy applications, innovative rate design, and direct load control techniques, are among the various factors accounted for in these analyses.

For more than twenty years, PNM has evaluated and, in some cases, pursued various options for meeting customer energy requirements. Such options have included:

1. Coal - Four Corners Project
   San Juan Project
2. Nuclear - Arizona Nuclear Power Project
3. Geothermal - Baca Geothermal Project
4. Hydro - Pumped Storage Project
5. Solar - Solar Hybrid Repowering Project
6. Conservation and Load Management Programs

These options, along with such technologies as wind, refuse burning, coal gasification, and fuel cells, are being continuously measured against:

- Commercial availability of the technology required for the option
- Availability of the required resources
- Environmental and social impacts
- Capital investment required
- The ability of the corporation to successfully implement the option in the time frame and dollars required.

Load growth in New Mexico is such that a combination of options is required to meet anticipated demand. No single option can meet all needs. Based upon current load growth forecasts, it is anticipated that additional base load generating capability will be required between 1990 and 2000. Therefore, PNM has established the New Mexico Generating Station Project. This project is intended to place emphasis on the coal option for meeting anticipated needs. In examining this option, the company is assessing the feasibility and availability of required resources (land, water, and fuel), and the probable impact on the environment from pursuing such a course. PNM views coal as the best available option for meeting part of the energy requirements of the 1990s. Accordingly, the company has chosen to subject the risks and benefits from coal development to detailed analysis. This analysis will be conducted in conjunction with continued study of the other options presently in use in the generating system.

In summary, the hallmark of system planning must be flexibility. Flexibility is required by the rapidly changing demands for electrical energy and by the rapid changes in the power supply options available to the company. This flexibility must be especially evident in planning new generation facilities. The eight to twelve years required to

> bring a coal station into commercial operation makes it difficult to establish a "date certain." Nevertheless, the same long lead-time from conception to commercial operation required that the company start very early to assess the risks and weigh the benefits of a given option. This process takes place while new data and altered circumstances dictate the need to accelerate or slow down the potential completion dates due to changes in the load and resource picture.
>
> 3. NEW MEXICO STATION EIS
>
> To assess the NMGS Project as the next potential coal option for the 1990s, PNM has requested the Bureau of Land Management (BLM) to consider the issuance of right-of-way grants for any proposed water conveyance system and transmission lines associated with the project.
>
> In response to PNM's application for those facilities, BLM, New Mexico State Office, was designated as the federal lead agency to prepare the EIS for the project in accordance with the NEPA process.
>
> Depending on the outcome of NEPA/EIS process, and the land, water, and fuel resource acquisitions, PNM recognizes that there are many other regulatory and permit requirements that would have to be met. These include a construction permit, location permit, numerous environmental approvals by state and federal agencies, and a certificate of convenience and necessity by the New Mexico Public Service Commission, before any construction would be allowed to begin.

PNM has also provided further elaboration on this statement of purpose [19]:

> On January 21, 1981, Public Service Company of New Mexico (PNM) submitted to BLM, our Statement of Purpose for the New Mexico Generating Station. Fundamental to the construction of that generating facility is the associated development of coal resources within the state of New Mexico.
>
> To this end we offer you further elaboration of PNM's purpose of contemplating the utilization of this valuable resource. This statement is in response to questions raised during recent public meetings and should serve to further document PNM's Phase I goals for NMGS.

Background

A. National Energy Policy

Electric utilities are faced with continued increases in electrical demand at a time when traditional energy resources are becoming scarcer and more expensive. The OPEC oil embargo of 1973/1974 forced the United States to review its current policies regarding the importation of large quantities of petroleum fuels for electrical energy production. Subsequent cost increases for gas and oil have also caused utilities to reevaluate their future fuel resources and those companies with the capacity are switching to other methods for supplying baseload electrical power such as coal or nuclear. The United States has adequate supplies of both coal and uranium to meet electrical power demands in the future. Indeed certain projections for New Mexico indicate there exist coal reserves which could last 200 to 300 years with current mining technology and at a similar removal rate. This resource is primarily located in the San Juan Basin of northwest New Mexico.

PNM management had the foresight to predict the rapid depletion of our nation's oil and gas resources in the mid-1950's. They realized that it made prudent business sense to shift from dependence on a single fuel source to multiple sources. PNM acquired coal reserves in the San Juan Basin to supply fuel for future units. At the same time, PNM was investigating other base load alternatives such as nuclear. Natural gas is now used primarily for peaking purposes.

PNM has delineated specific objectives, through its fuels planning process by which compliance to National Energy Policies may be met.

These are: (From PNM's Fuels Management Document [Draft])

1. Acquire and/or use those natural resources that are regionally abundant for base load, intermediate and peaking power generation;
2. Improve existing facilities (including transmission) for greater efficiency and reliability while maintaining a desirable environment;
3. Study the possibility of converting existing plants to accept new fuels or utilize new processes to generate electricity based on economics, costs, and benefits;

4. Implement methods to minimize the environmental impact of power production facilities;
5. Promote strong load management and conservation programs;
6. Investigate possibilities for implementing new fuel resources and technologies, such as coal gasification, solar, wind, and geothermal development; and
7. Assure conformity of fuels guidelines with provisions outlined in the PNM Corporate Goals and Objectives.

As can be seen from item #1, a priority is given to development of regional fuel resources.

Additionally, PNM has a basic commitment to assist in stimulating the economy of New Mexico; utilization of Fruitland Formation Coal from the San Juan Basin NM, therefore, meets PNM's primary objectives.

5.3 REVIEW OF STATEMENT OF PURPOSE

As noted in Section 1.0, the key questions the BLM addressed in reviewing PNM's statement of purpose were:

- Is this purpose in accord with PNM's statutory responsibilities and corporate objectives?
- Is this purpose in accord with accepted practice within the electric utility industry?
- Is this purpose consistent with other public statements of purpose by PNM?

The conclusion with respect to each question, and the basis for the conclusion, is presented below.

Is This Purpose in Accord With PNM's Statutory Responsibilities and Corporate Objectives?

Investigation of a range of future supply alternatives, including a large coal-fired power plant like New Mexico Generating Station, is a normal planning activity carried out by electric utilities. In its statement of principle [20] PNM states that it recognizes its obligations to:

> Our Customers
> An adequate and reliable source of electric and water service at the lowest reasonable cost;
>
> Our Shareholders
> A reasonable return on, with optimum security of, their investment;
>
> Our Employees
> An objective opportunity to progress and grow through productive and meaningful participation; and
>
> Our Future Generations
> A legacy of adequate electric and water service provided through free enterprise with environmental and economic compatibility.

NMGS, viewed as a potentially attractive source of electrical power by PNM, is consistent with these corporate objectives.

Is This Purpose in Accord With Accepted Practice Within the Electric Utility Industry?

An accepted view within the utility industry is that coal and nuclear plants are potentially attractive as base load generation facilities [21], and investigation of NMGS as a potential power source utilizing coal is consistent with this view.

Is This Purpose Consistent with Other Public Statements of Purpose by PNM?

In its most recent annual report, PNM states [20] "the New Mexico Generating Station (NMGS) project team is currently working with the Bureau of Land Management to complete the environmental impact statement required of such projects. The plant is designed to meet the energy needs of our customers in the 1990s.... Once the environmental impact statement is completed and updated studies on options to meet the future load growth of New Mexico are finished, a decision on whether to construct the New Mexico Generating Station at Bisti will be made." The NMGS statement of purpose is consistent with this recent public statement by PNM.

6.0
ASSESSMENT OF NEED

6.1 PNM's ASSESSMENT OF NEED

In presenting its assessment of the need for NMGS, PNM has developed five different load growth scenarios. These scenarios are:

- low scenario
- middle scenario
- "strong growth" scenario
- high scenario
- "potential industrial loads" scenario

The high, middle, and low scenarios were developed by PNM's load forecasting group using an econometric model utilizing historical relationships between electrical growth and economic trends. They are presented in PNM's "1981-2001 forecast of energy sales and peak demands" [22]. PNM's middle forecast is their planning scenario, used in financial and other planning. PNM has supplied the following discussion of high and low growth scenarios [23].

> The high and low load growth scenarios projected by the econometric model are intended to bracket the range of growth likely to be achieved within the PNM service area. In the past, our philosophy has been to examine historical rates of growth and present a low scenario that reflected the lowest rates of economic growth experienced by PNM, and to present a high scenario showing sustained growth at the highest levels ever experienced by PNM. Since the Bureau of Business and Economic

Research (BBER) prepared three sets of economic forecasts for PNM in 1981, they have followed the philosophy of providing a 'range of reasonable possibilities' [Ref. 22, page 21, bottom]. Also, Load Forecasting has been requested to provide 'credible' scenarios to generation planning. PNM does not consider its bandwidth to be a confidence interval since it was not developed by statistical means, nor does it have any probability values assigned to it.

In addition to its low, middle, and high scenarios, PNM has developed two additional scenarios. The first, called a "strong growth" scenario is the average of the middle and high scenarios. PNM states [9] that "PNM believes [the strong growth scenario] is the realistic scenario upon which to develop prudent long-term system expansion plans which afford PNM the ability to meet the energy requirements of an economically strong New Mexico economy." PNM has used the strong growth scenario when presenting calculations to show the need for NMGS. PNM also states [23] that "in the same manner, PNM presented its scenario of potential industrial growth to reflect reasonable possibilities that were not captured by the econometric model. PNM has an obligation to serve these loads, should they materialize." PNM further states [9] that the "Potential Industrial" scenario is "a scenario whose load estimates are based on actual inquiries and preliminary negotiations with companies considering building large new facilities which would require PNM electric service. These additional potential industrial customers could increase the demand on PNM's system by 1000 MW over the 1983 through 1990 time period. This scenario is the PNM LGD [middle scenario], coupled with acceleration of natural gas deregulation to 1982 and explicit incremental additions to serve these major industrial loads just mentioned." In response to an inquiry, PNM noted that by the acceleration of natural gas deregulation PNM meant that it used the natural gas price projections from its high scenario in developing the "Potential Industrial" scenario.

Tables 6-1 and 6-2 and Figures 6-1 through 6-4 show energy growth and peak demand growth forecasts for the five scenarios as well as existing and planned supply capacity excluding NMGS. For comparative purposes, Table 6-3 shows historical growth and Table 6-4 compares historical and forecast growth rates. The units in these tables are gigawatthours per year (GWh/yr) and megawatts (MW). These comparisons are shown for the forecasts of total future requirements as well as for forecasts which exclude sales for resale and New Mexico Electric requirements. (Sales for resale are sales of electricity by PNM to another party, which in turn resells the electricity.) The reason for presenting figures which exclude sales for resale and New Mexico Electric requirements is that the remainder represents the requirements of PNM's direct customers. Thus the historical and forecast figures for this case (designated "Base Requirements" in Table 6-3 and "Base MW" or "Base GWh" in Table 6-4) allow a straightforward comparison between historical and forecasted growth of electricity use for this important group of customers. Each unit of NMGS would have a capacity of 500 MW at a 0.65 capacity factor and thus would supply 2847 GWh/yr of electrical energy. The schedule for commercial operation is: Unit 1, 1990; Unit 2, 1993; Unit 3, 1995; and Unit 4, 1998.

Comparisons between historical and forecasted growth of sales for resale require care, since these electrical requirements historically may have been provided by other sources before PNM furnished the electricity. Similarly, in the future the power may need to be provided by other sources if PNM does not provide it.

PNM notes [16] that no attempt is made in the 1982-1988 time frame to account for contractual nonfirm loads, the most notable of which is PNM's 236 MW contingent sale to San Diego Gas and Electric Company. Thus PNM will have less generating reserve in the 1980s than shown in Tables 6-1 and 6-2.

Table 6-1. SUMMARY OF PNM FORECAST SCENARIOS FOR TOTAL ELECTRICAL ENERGY AND EXISTING AND PLANNED SUPPLY CAPACITY, EXCLUDING NMGS (GWh/yr)

	Scenario					Existing and Planned Capacity (excluding NMGS)	Energy Supplied by NMGS[a]
Year	Low	Middle	Strong Growth	High	Potential Industrial		
1981	6,540	6,597	6,665	6,733	6,599	5,961	0
1982	6,945	7,101	7,211	7,371	7,160	8,709	0
1983	6,944	7,198	7,491	7,784	7,696	9,518	0
1984	6,731	7,020	7,418	7,816	8,815	10,326	0
1985	6,927	7,365	7,756	8,147	9,276	10,326	0
1986	7,436	7,979	8,397	8,814	12,550	11,135	0
1987	8,147	8,763	9,185	9,607	13,227	11,135	0
1988	8,908	9,613	10,021	10,428	14,289	11,135	0
1989	9,628	10,312	10,797	11,281	14,899	11,135	0
1990	10,147	10,936	11,530	12,124	17,045	11,135	2,847
1991	10,469	11,332	12,059	12,785	17,395	11,135	2,847
1992	10,834	11,850	12,738	13,626	17,880	11,135	2,847
1993	11,132	12,333	13,405	14,477	18,361	11,135	5,694
1994	11,498	12,872	14,149	15,425	18,837	11,135	5,694
1995	11,817	13,437	14,950	16,462	19,395	10,373	8,541
1996	12,186	14,014	15,795	17,576	20,023	10,373	8,541
1997	12,497	14,568	16,621	18,673	20,648	10,373	8,541
1998	12,860	15,144	17,503	19,862	21,327	10,373	11,388

Sources: Tables B-4, B-14, B-15, B-16, B-43, and B-44. All figures include NME and contracted sales. Does not include contingent sales 1982-1988.

[a] NMGS would consist of four 500-MW units operating at a capacity factor of 0.65. The schedule for commercial operation assumed in this table is Unit 1, 1990; Unit 2, 1993; Unit 3, 1995; and Unit 4, 1998.

Table 6-2. SUMMARY OF PNM FORECAST SCENARIOS FOR TOTAL PEAK ELECTRICAL REQUIREMENTS AND EXISTING AND PLANNED SUPPLY CAPACITY, EXCLUDING NMGS (MW)

	Scenario						
Year	Low	Middle	Strong Growth	High	Potential Industrial	Existing and Planned Capacity (excluding NMGS)	Capacity Provided by NMGS[a]
1981	1261	1276	1291	1307	1276	1231	0
1982	1288	1327	1357	1387	1339	1655	0
1983	1256	1312	1384	1454	1417	1785	0
1984	1250	1316	1410	1502	1664	1915	0
1985	1324	1420	1514	1609	1790	1915	0
1986	1410	1536	1639	1742	2395	2045	0
1987	1540	1684	1793	1902	2520	2045	0
1988	1691	1843	1955	2065	2713	2045	0
1989	1802	1969	2104	2237	2824	2045	0
1990	1885	2082	2245	2407	3217	2045	500
1991	1939	2154	2348	2543	3284	2045	500
1992	1981	2232	2464	2695	3355	2045	500
1993	2036	2330	2605	2879	3461	2045	1000
1994	2101	2437	2759	3079	3558	2045	1000
1995	2156	2549	2924	3299	3671	1929	1500
1996	2219	2660	3098	3535	3798	1929	1500
1997	2273	2767	3268	3767	3923	1929	1500
1998	2332	2879	3450	4020	4058	1929	2000

Sources: Tables B-4, B-11, B-12, B-13, B-43, and B-44. All figures include NME, contracted sales, and 20 percent minimum reserve margin. Does not include contingent sales 1982-1988.

[a] NMGS would consist of four 500-MW units, with Units 1-4 beginning operation in 1990, 1993, 1995, and 1998, respectively.

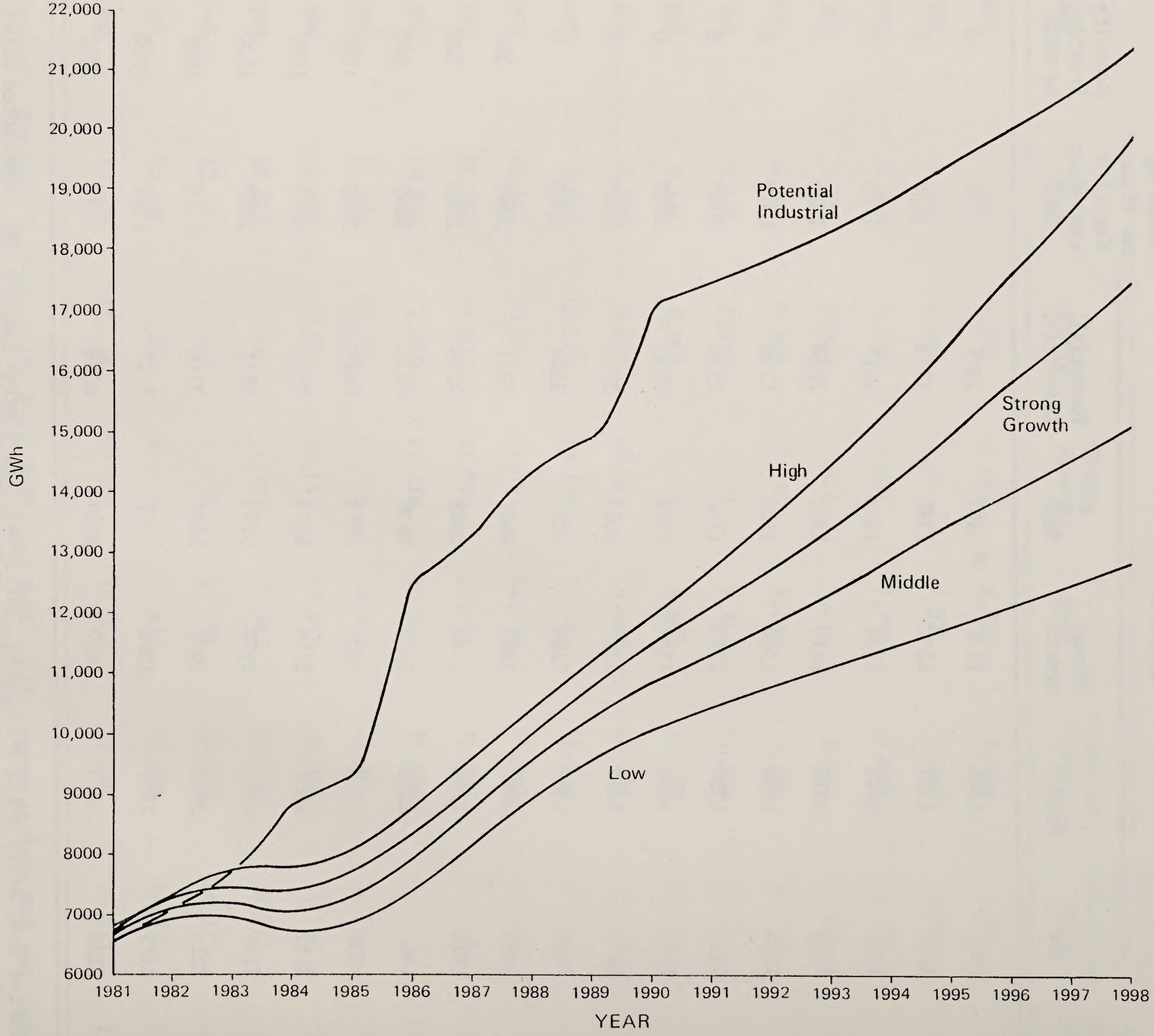


Figure 6-1. SUMMARY OF PNM FORECAST SCENARIOS (total requirements GWh)

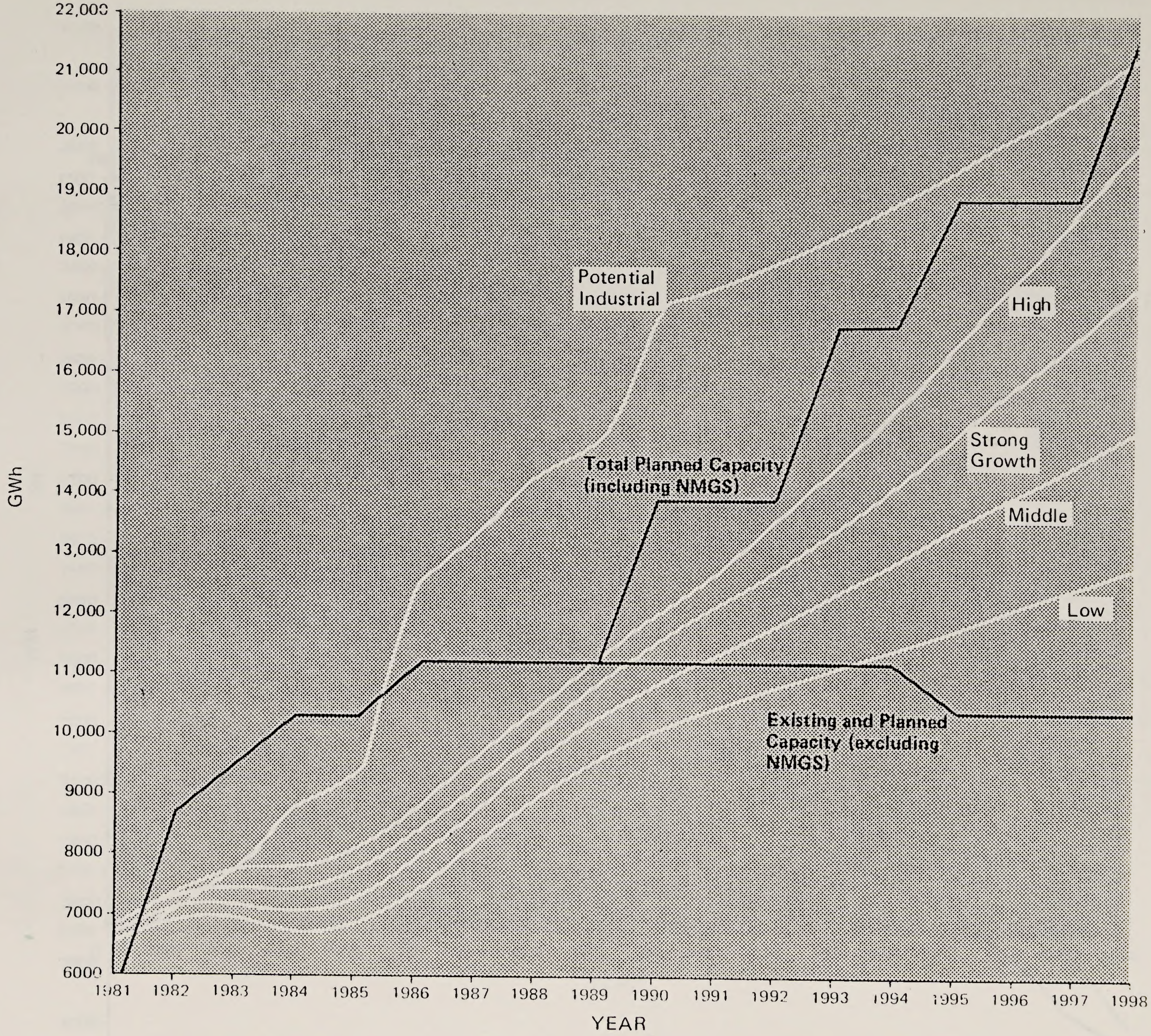


Figure 6-2. SUMMARY OF PNM FORECAST SCENARIOS AND PLANNED CAPACITY ADDITIONS (total requirements GWh)

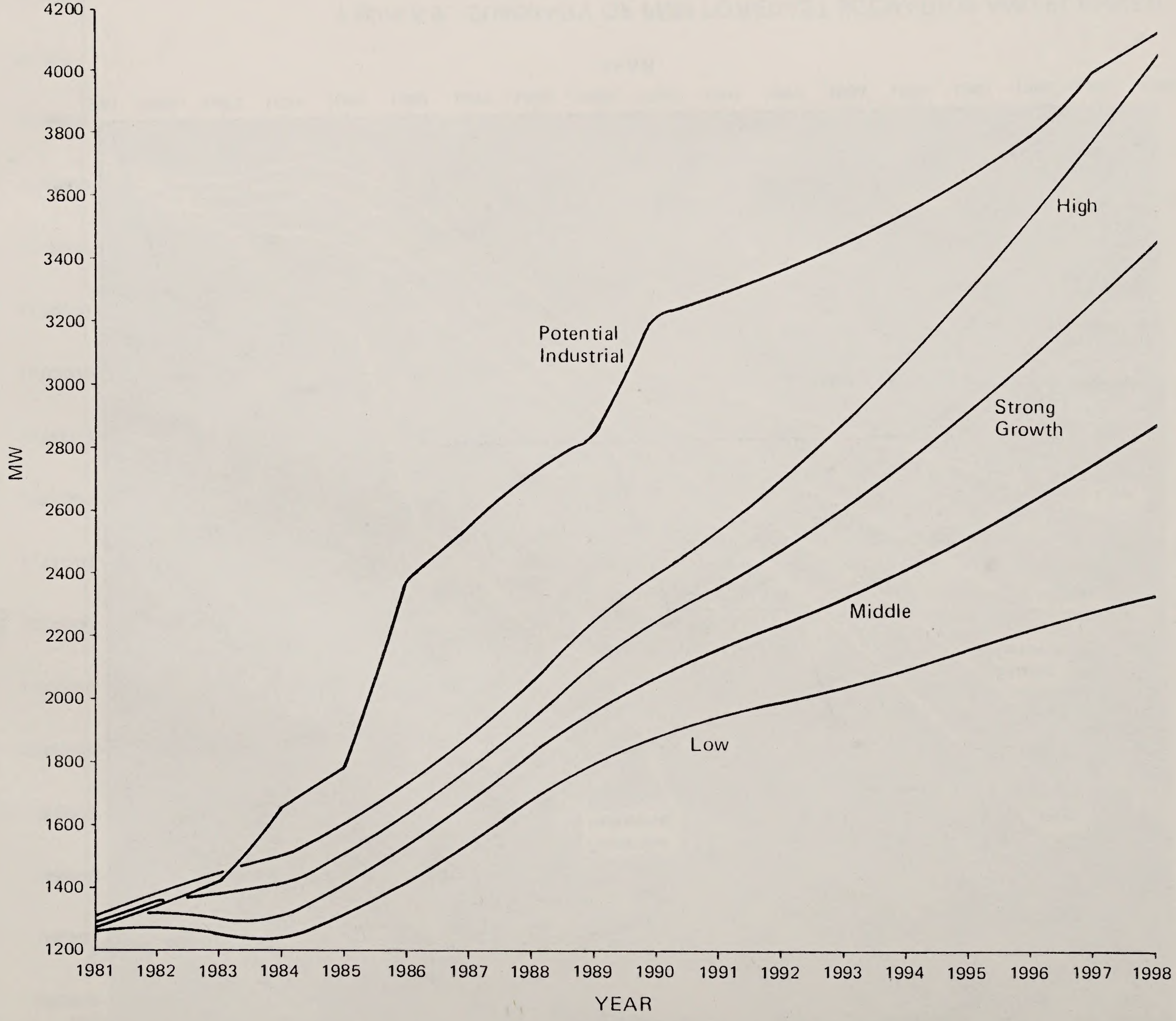


Figure 6-3. SUMMARY OF PNM FORECAST SCENARIOS (peak requirements MW)

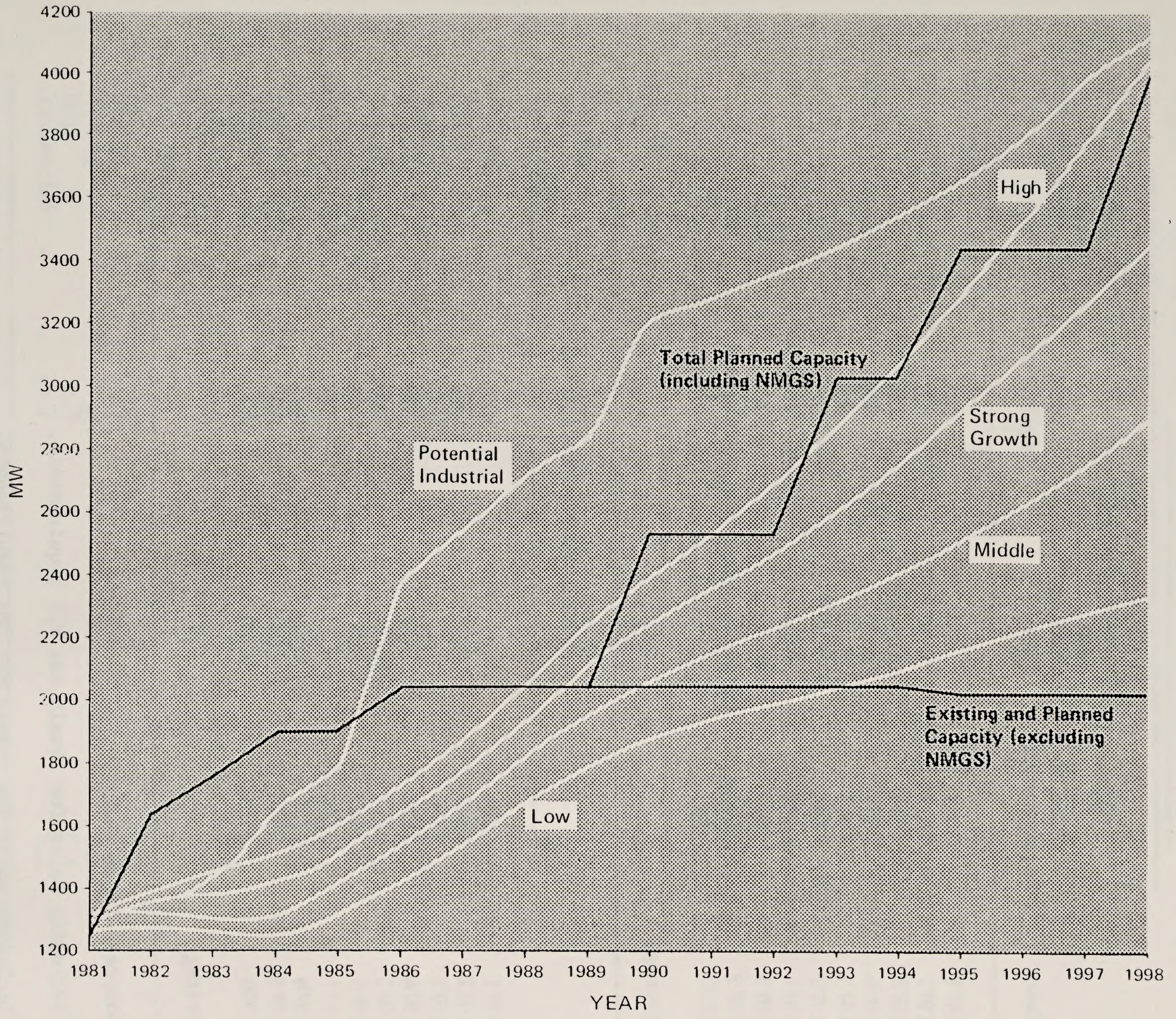


Figure 6-4. SUMMARY OF PNM FORECAST SCENARIOS AND PLANNED CAPACITY ADDITIONS (peak requirements MW)

Table 6-3. SUMMARY OF PNM HISTORICAL ELECTRICAL REQUIREMENTS

	Power Requirements (MW)			
Year	Base Requirements[a]	% Change From Preceding Entry	Total Requirements[b]	% Change From Preceding Entry
1971	443	-	634	-
1972	473	6.8	677	6.8
1973	514	8.7	736	8.7
1974	549	6.8	800	8.7
1975	547	<0.9>	806	0.8
1976	584	7.4	871	8.1
1977	620	6.2	977	12.2
1978	680	10.0	1096	14.3
1979	695	1.8	1157	5.6
1980	724	4.2	1238	7.0
Average		5.6		7.7
	Energy Requirements (GWh)			
1971	2384	-	3003	-
1972	2602	9.1	3262	8.6
1973	2736	5.1	3437	5.4
1974	2830	3.4	3653	6.3
1975	3229	14.1	4093	12.0
1976	3489	8.0	4469	9.2
1977	3772	8.1	5157	15.4
1978	3781	0.2	5471	6.1
1979	3953	4.5	5938	11.9
1980	3903	<1.3>	6121	3.1
Average		5.6		8.2

Source: Table B-17.

[a] Excluding sales for resale and NME requirements.

[b] Including sales for resale and NME requirements.

Table 6-4. COMPARISON OF HISTORICAL AND FORECAST GROWTH RATES OF ELECTRICAL USE

	Historical (1971-1980)	
	Avg. % Annual Change	Max. % Annual Change
Base MW	5.6	10.0
Total MW	7.7	14.3
Base GWh	5.6	14.1
Total GWh	8.2	15.4

	Forecast		
	1981-1989	1989-1998	1981-1998
	Avg. % Annual Change	Avg. % Annual Change	Avg. % Annual Change
Base MW			
Low	6.3	3.3	4.7
Middle	7.8	5.0	6.3
Strong	8.4	6.4	7.4
High	9.3	7.6	8.4
Industrial	9.5	6.4	8.7
Total MW			
Low	4.6	2.9	3.7
Middle	5.6	4.3	4.9
Strong	5.6	5.5	6.0
High	6.9	6.7	6.8
Industrial	10.4	5.6	7.0
Base GWh			
Low	7.5	3.6	5.5
Middle	8.7	5.0	6.7
Strong	9.1	6.3	7.6
High	9.7	7.4	8.5
Industrial	14.8	4.4	9.2
Total GWh			
Low	5.0	3.3	4.1
Middle	5.7	4.4	5.0
Strong	6.2	5.5	5.8
High	6.7	6.5	6.6
Industrial	10.7	4.1	7.1

Sources: Computed from Tables B-11 through B-17 and Tables B-43 and B-44 by WCC.

Base: PNM requirements only. Excludes NME and sales for resale.

Total: Includes PNM requirements, NME requirements and sales for resale.

To prepare the forecasts used in its statement of need for NMGS, PNM has used an econometric forecasting model based on trend analysis using multiple regression. This type of model uses historical data on a variety of input variables to develop a formula for estimating the future level of electric sales given the future levels of the input variables.

PNM's load forecasts are described in detail in "1981-2001 Forecast of Energy Sales and Peak Demands" [22] and are reviewed in Appendix B of this report. Forecasts of sales are prepared for five customer classes: residential, commercial, industrial, miscellaneous, and the City of Gallup, which purchases power for resale. The forecasting models are applied separately for each operating division and the results are summed to obtain total sales. Once the econometric models have been used to compute the total electrical energy sales for each category for each year, the peak demand is computed using historical load factors for each category.

The total energy sales and peak load forecasts form the major output of the econometric model. Before the forecast is complete, however, several additional components are added in, including resale contracts with other electric utilities, bulk transmission losses, and system reserve.

The load forecast models use input data from a variety of sources. In general, the values used by PNM for these input data assume continuing substantial economic growth for New Mexico in the future plus changes in relative prices of electricity vs. possible substitutes, such as natural gas, which would result in higher electrical consumption.

Table 6-5 identifies the input variables used in the forecasting model. A comparison is given in Appendix B of their rates of change both historically and in the three primary PNM forecast scenarios.

6.2 REVIEW OF ASSESSMENT OF NEED

As noted in Section 1.0, the key questions addressed in reviewing PNM's assessment of need were:

- Was the assessment conducted using methods that are generally used within the utility industry?
- Were the assessment methods reasonably applied to the situation and environment under which PNM operates?
- Are the assessment results obtained consistent with other public statements on need by PNM?

The approach to answering these questions was to conduct a review of documents provided by PNM describing the need analyses, which identified the types of models used, the input variables used, and the adjustments made to the model results to arrive at the final projections. Next, each input variable was reviewed for its appropriateness and source. Where deemed necessary, original source documents were obtained to establish whether the input data were used appropriately and to identify assumptions implicit in the source data. Next, the modeling approach and formulas were reviewed for appropriateness and use of accepted techniques. Finally, any adjustments made by PNM to the model results were reviewed for appropriateness and compatibility with the overall modeling approach. This analysis of PNM's need analyses clarified and reviewed the

Table 6-5. SUMMARY OF INPUT VARIABLES FOR PNM FORECASTING MODELS

Variable	Units	Models Used In
Per capita personal income	1967 dollars	Residential kWh/cust Commercial kWh/cust
Amount of typical 500 kWh residential electric bill	1967 dollars	Residential kWh/cust
Real price of electricity for commercial customers	¢/kWh in 1967 dollars	Commercial kWh/cust
Real price of electricity for Gallup customers	¢/kWh in 1967 dollars	Gallup GWh
Amount of typical 10 mcf residential natural gas bill	1967 dollars	Residential kWh/cust
Amount of typical 125 mcf commercial natural gas bill	1967 dollars	Commercial kWh/cust
Ratio of real price of electricity for industrial customers to amount of typical 2500 mcf industrial natural gas bill	-	Albuquerque base industrial GWh
Mean of average temperatures for June, July, and August	°F	Residential kWh/cust
Annual heating degree-days	-	Residential kWh/cust Commercial kWh/cust
Population	thousands	Residential customers
Average household size	-	Residential customers
Annual average commercial employment	-	Commercial kWh/cust
Dummy variable to account for shifts of use since 1973 oil embargo	-	Commercial kWh/cust
Industrial employment	-	Albuquerque base industrial GWh
U.S. gross national product	-	Albuquerque base industrial GWh
Annual average employment, Gallup	-	Gallup GWh

analytical process from initial assumptions to final results and established whether PNM used accepted methods in a reasonable manner to arrive at its projections.

In addition to the review of documents associated with PNM's forecasts, interviews were conducted with other parties knowledgable about New Mexico electrical needs. Documents provided by these sources were also reviewed [2,7].

The conclusion with respect to each question, and the basis for the conclusion, is presented below.

Was the Assessment Conducted Using Methods That Are Generally Used Within the Utility Industry?

PNM's forecasting methods, input assumptions, and electrical forecasts are reviewed in Section 6.1 and considered in detail in Appendix B. The methods that PNM used are consistent with those used by other utilities in similar situations and are generally used within the utility industry [24,25,26]. (These references present the views of experienced utility industry experts on need assessment. Utility practice is reviewed in Section 3.0.)

Were the Assessment Methods Reasonably Applied to the Situation and Environment Under Which PNM Operates?

In the judgment of the BLM, the assessment methods were reasonably applied to the situation and environment under which PNM operates, as regards the assessment of need for NMGS. PNM's forecast results, which are summarized in Section 6.1 and reviewed in detail in Appendix B, show the following:

- PNM's middle scenario projects that existing and planned capacity will not be sufficient by the early 1990s.

- PNM's high and "industrial loads" scenarios project that existing and planned capacity will not be sufficient by the mid to late 1980s.

- All of PNM's forecast scenarios project a higher rate of growth in the 1980s than occurred in the 1970s, if direct sales only, excluding sales for resale and New Mexico Electric, are considered. In the 1990s these forecasted rates of growth taper off somewhat but are still generally higher than the 1970s rates.

- All of PNM's forecast scenarios project a lower rate of growth in the 1980s than in the 1970s if NME demand and sales for resale are added to direct PNM demand.

The forecast which PNM is using as a basis for determining that one unit of NMGS may be needed as early as May 1990 is higher than the most likely, or expected, future need for electricity. Within the utility industry it is accepted practice to use higher than expected forecasts in the early stages of planning for new electrical generating facilities. The reason for this, as discussed in more detail in Section 3.3, is that utility planners believe that risks and potential costs to the utility and its customers are reduced by planning for a higher than expected growth of electrical needs [10].

Are the Assessment Results Obtained Consistent with Other Public Statements on Need by PNM?

The forecast results obtained in the NMGS assessment of need are at variance with certain other public statements on need by PNM, specifically submittals and testimony by PNM during the recent New Mexico Public Service Commission Case 1577 [13,14]. PNM has furnished the following explanations for these variances [12,15]:

- Certain assumptions made by PNM in earlier forecasts have been reassessed in light of more recent information and developments; changes in these assumptions have resulted in changes in the forecasts.

- Certain of the other forecasts were prepared for purposes other than planning construction of a new power generating facility; these include assessing future need for capital and scheduling of bond or stock issues. For these purposes it is appropriate to utilize most likely, or expected, forecasts rather than the higher forecasts assumed for NMGS.

These explanations are concluded to be reasonable.

APPENDIX A

This material was furnished by Public Service Company of New Mexico.

NMGS PURPOSE AND NEED

EIS TECHNICAL APPENDIX

NEED FOR POWER

SUPPORT STUDIES AND DOCUMENTATION

Load Forecasting Section

Load Management and Forecasting Department

Public Service Company of New Mexico

December 4, 1981

TABLE OF CONTENTS

Chapter — Page

I. PNM Planning Process 1

Planning Versus Budgeting 1

Forecasting Process 3

II. PNM Planning Scenarios 8

Baseline Forecast 9

High/Low Scenarios 26

Industrial Growth Potential in New Mexico 28

Planning Scenario 29

Summary of Results 30

Conclusions 34

CHAPTER I

PNM PLANNING PROCESS

The following paragraphs provide an overview of the planning process at Public Service Company of New Mexico (PNM). A distinction is drawn between planning, a dynamic process in which long-run alternatives are examined and evaluated, and budgeting, a static "snapshot" view of long-run plans as they result in current expenditures. Predictions of future activity, or forecasts, serve important functions in both the budget and planning processes. The nature of the forecasting process is determined to a great extent by the manner in which the forecast is to be applied.

Planning Versus Budgeting

The planning process begins with the establishment of long-range corporate goals. The primary goal of PNM is to provide its customers with an adequate and reliable source of electricity at the lowest reasonable cost and its shareholders with a reasonable return on their investment. Once long-range corporate goals are established, strategic planning leads to the development of more detailed objectives that must be effected in order to attain the stated goals. From this point, emphasis is placed on tactical planning, or determining the best way to accomplish specified objectives. Operational plans are then constructed which identify the actual tasks that must be performed over time to achieve the goals and objectives of the corporation.

The planning process operates in a dynamic environment in which the optimal strategies are subject to change in response to changes in external conditions. The process is subject to controls which take the form of management review at various stages in the analysis and preparation of plans. This review process ensures that plans are consistent and compatible with PNM's stated goals and objectives.

The key planning activities necessitate the consideration of three major issues: demand, supply, and finance. The integration of these major issues is accomplished through the "Integrated Planning Loop" (IPL), a tool which consists of a series of computerized models. The primary models are concerned with Load Forecasting, System Planning, and Financial Planning which includes rate impact assessments. The IPL allows for a common basis from which to evaluate alternatives. A major IPL application is the simulation of potential economic, energy supply and demand, and financial conditions. A large number of simulations are possible since the models have shortened the period of time required for impact assessment.

In summary, planning is concerned with defining long-range objectives and evaluating alternatives to achieve those objectives. It is necessarily dynamic given the rapid change and high level of uncertainty facing the utility industry today. A budget, on the other hand, is concerned with the short run and is usually not subject to change once it is approved. The budget may be viewed as a summary of long-run plans as they result in current expenditures.

PNM's Corporate Budget is developed annually and consists of several components: the construction, operating, and manpower budgets. The budget process begins at the lowest reporting level, the functional unit, where actual expenses are incurred and control achieved. The Corporate Budget serves four major functions. First, it is an operational tool for near- and long-term financial planning activities. The budget also serves as a management reporting and control device for the budget year and provides a benchmark for future planning activity. Fourth, the budget provides valuable feedback into the development of future corporate goals and objectives.

Forecasting Process

The preparation of load growth forecasts is an integral part of PNM's planning and budgeting processes. On an annual basis, the Company prepares an official load forecast, contained in the Load Growth Document, which reflects PNM's best perception of the energy requirements and annual peak demands it must be able to meet for the next ten years. The Load Growth Document is used specifically for corporate budgeting and fulfills several purposes. In the short-term, the load forecast supports the next year's budget. The ten-year forecast forms the basis for revenue projections, load management studies and marketing strategies. In addition, the long-term (to 20 years) forecast, based on the official ten-year projection, forms the basis for system expansion planning and long-range transmission studies.

The long-range (20 year) forecast is developed by the Load Forecasting Section after final approval of the Load Growth Document. In addition, high and low load growth scenarios are developed around the base case. Other load growth scenarios are often developed to explicitly incorporate potential known additions to load (e.g., NME). The models, methods, and assumptions underlying these forecasts are reviewed in Chapter II.

The ten-year corporate forecast used for budgeting processes is a synthesis of the independent forecasts of several groups in the company, incorporating many different methods of analysis and projection techniques. The method employed in any particular instance depends on the component under consideration, the time period of the forecast, and the functional responsibility of the group who develops the forecast. Among the groups involved in forecasting at PNM are each of the operating divisions, the Load Forecasting Section, the Load Management Section, Power Operations, and Power Contracts Section, Technical Services and a special Mining Task Force.

Each operating division prepares a ten-year forecast of electric sales and customers. The operating divisions rely heavily on their frequent contacts with customers, builders, and municipal officials to forecast load growth in the near-term (one to three years). Their long-term forecast is primarily an extrapolation of the short-term forecast and long-term trends.

The Load Forecasting Section, which is officially charged with responsibility for the long-term projection, also develops ten-year sales and customer projections. The primary approach taken by the Load Forecasting Section is econometric modeling. This approach to identifying the underlying marketplace decisions is used to derive residential and commercial use per customer and customers, base industrial sales, and sales to the City of Gallup. Other components are related to this core by statistical relationships to ensure overall consistency. The Load Forecasting Section works closely with the Load Management Section in examining changes in energy usage from an end-use perspective and has used this approach to validate the econometric results.

The sales for resale forecast prepared jointly by Power Operations and the Power Contracts Secton is derived from contractual obligations and historical load shape patterns of four firm resale customers. Technical Services performs load flow studies to project losses on PNM's bulk transmission system. The Mining Task Force relies on engineering relationships, production capabilities, and environmental/regulatory considerations to forecast electrical demand for uranium and coal mining customers. The impacts of various load management programs are also incorporated into PNM's official Company forecast. Load Management impacts are expressed as reductions to base demand as shown in the Load Growth Document. These peak reductions also imply load shape changes in the future, which in turn have impacts on system expansion and other planning concerns.

The forecasts developed by these various groups in the company are subject to a management review process. Each division's load growth projections are reviewed for accuracy and consistency by senior management. The Load Forecasting Section compiles into one document the results of its forecasting process and the results of the Technical Services Section and the Power Contracts Section. Also included in this forecast is the mining projection developed by the ad hoc Mining Task Force. This preliminary forecast is likewise scrutinized by senior management.

After passing through the management review process, the various forecast components are integrated by management to form the official ten-year load forecast. In the current Company forecast, the first three years (1981 to 1983) sales and customer forecasts are those developed by the operating divisions. The remainder of the ten-year forecast is a merger of the divisions' forecast and the Load Forecasting Sections's forecast, with primary emphasis in the long-term placed on the growth projections resulting from the Load Forecasting Section forecast.

Once the Load Growth Document is approved, the Load Forecasting Section extends the resultant ten-year projection to 20 years and develops peak demands and alternate growth scenarios around the 20-year base case projection.

Long-range projections of electric demand are required to determine the need for capital expansion, which includes the need for generation facilities as well as the transmission and distribution network. Thirty year studies are conducted to evaluate alternative generation expansion scenarios. Studies are performed for the specific goal of providing PNM customers, now and in the future, with an adequate and reliable source of electricity. Long lead times for plant require that load projections and system expansion plans be developed for 20 and 30 years out in the future. This long-range planning occurs in a dynamic environment where assumptions and models are reviewed and updated continually. High/low projections and alternative load growth scenarios are developed to assess the sensitivity of generation expansion scenarios to changing economic and fuel price parameters.

CHAPTER II

PNM PLANNING SCENARIOS

This chapter addresses five specific load growth scenarios. The first scenario is the official ten-year base line forecast contained in the Load Growth Document which represents the Company's best perception of future loads. This forecast is extended to 20 years by the Load Forecasting Section and is used by Generation Planning to evaluate alternative generation expansion scenarios. Third, high/low load growth scenarios are developed by the Load Forecasting Section around the base case. All three of these scenarios, the base-line, the 20 year, and the high/low, are based on the econometric model which is discussed thoroughly in the paragraphs below. In addition, a fourth scenario is reviewed which contains an explicit adjustment to the econometric model to incorporate the industrial growth potential in the state of New Mexico. This scenario contains loads from potential future industrial customers who have contacted PNM regarding service. The fifth scenario is the planning scenario which reflects a middle line projection from the entire range of load growth scenarios. The planning scenario was used by planners to quantify via the Company's computer models (see Chapter I, page 2, "Integrated Planning Loop") the potential impacts of future load growth on PNM's system. The models, methods, and assumptions underlying these forecasts are presented below.

Baseline Forecast

This section presents the major models and methods used to arrive at PNM's "base case" load forecast (the Load Growth Document). Several different modeling approaches are used to forecast major components of total system load. The discussion will center around three major areas: class energy sales and customers, class contributions to peak demands, and system demands and energy requirements.

Class Energy Sales and Customers

Several groups within PNM prepare ten-year forecasts of energy sales and customers prior to reconcilation. The Load Forecasting Section is primarily responsible for the long-term forecast and uses an econometric model as the core of its forecasting system. The Load Management Section maintains a detailed end-use model of the residential class that is generally used for sensitivity and scenario analysis. This year it was also used to provide support for the Load Forecasting Section's econometric forecast. The Mining Task Force provides support for the forecast of energy sales to mining customers in the Western Division. Its approach is to model the electrical requirements of the various processes involved in uranium and coal production. It also provides a review of regulatory and environmental constraints that may effect mineral production. Each operating division is charged with the preparation of a ten-year sales forecast as part of the annual budget preparation. Their emphasis, however, is on the near term (1-3 years).

Near-term Forecast (Operating Divisions)

The first few years of the corporate sales forecast are the direct input of the operating divisions. Generally, the divisions forecast by rate code within customer class, and rely heavily upon customer contacts and expert judgments. They continually monitor construction activity and stay abreast of municipal development plans. Their major assumptions are listed below:

1. Housing construction is generally agreed to be "bottoming out" in 1981, although some divisions are forecasting increases in 1981 over 1980. Recovery will be slow, and perhaps take as long as five years.

2. Interest rates will remain high in the near term.

3. Inflation will remain at double-digit rates.

4. Conservation including such phenomena as improved building standards and smaller homes will continue.

5. Unemployment in the Albuquerque area will decrease due to the influx of several major manufacturing firms. Elsewhere, it will be about normal.

The 1981 corporate forecast reflects modifications to the Western Division's coal forecast for delays in some customer starting dates, as were suggested by the Task Force. The uranium forecast represents the Western Division's outlook through 1985, and the rate of growth suggested by the Task Force thereafter. This forecast reflects a minimum level of ore production required to support existing nuclear power plants and those currently under construction.

Econometric Forecasting System

The corporate forecast of energy sales and customers is an integration of the division's near term projections through 1983 and the Load Forecasting Section's long-range projections. The primary analytical tool used by the Load Forecasting Section is econometric modeling. The Load Forecasting Section's Econometric Forecasting System is composed of separate components for each of six customer classes. The core of the system is an econometric model that identifies relationships between energy use and economic factors in the residential, commercial and industrial classes, and for one resale customer. The econometric model is a tool for identifying the major factors underlying market-place behavior. It is grounded in economic theory which states that economic agents (individuals and firms) operate to maximize their economic welfare (satisfaction, or profit). In this behavior they respond to relative prices and income. The models are estimated statistically on a historical data base. Statistical analysis of the other classes provides consistent relationships among the six components of total energy sales.

The residential and commercial components identify separately the determinants of average use per customer and the average number of customers. Average energy use is modeled as a function of energy prices (electric and natural gas), personal income, and employment (in the commercial class). Weather variables are included to account for variations in seasonal energy use. The commercial model also includes an embargo variable to account for a structural shift in average use per customer since the Arab oil embargo (post-1973). Customers in both classes are a function of total housing units, which are modeled as a function of population and average household size. All equations in these sectors are estimated on a historical time series pooled across PNM's operating divisions.

In previous years, the residential model has been disaggregated by dwelling unit type (single or multifamily) and by user type (conventional or all electric), by division. A slightly different approach was taken this year from previous forecasts. A baseline forecast was prepared using the basic econometric model by division. Average use per customer is multiplied by the number of residential customers and summed across divisions to arrive at the class sales forecast. Residential customers are calculated by subtracting master-metered apartments from total housing units. Sensitivity analysis and a disaggregated end-use approach were used to validate these econometric results. The commercial model is similar to the residential model except that exogenous forecasts of irrigation sales and sales to master-metered apartments are added to a base commercial forecast. Commercial customers are forecast by a ratio to total housing units.

The industrial class is disaggregated into three major components in the Load Forecasting System. Base industrial sales in the Albuquerque area are modeled econometrically as a function of relative energy prices (electric versus natural gas), industrial employment and gross national product (GNP). These last two variables serve as indicators of local and national economic activity, respectively. This equation is estimated using a time series data base. Industrial sales in the other divisions are ratioed to the Albuquerque area or extrapolated based on historical trends. An explicit adjustment for electrically intensive industries is made to the base forecast. A forecast of sales to mining customers is provided by the Mining Task Force and is incorporated into the Load Forecasting System. The forecast for Kirtland Air Force Base (USAF) is based on information provided to PNM by Air Force officials.

Sales forecasts for the minor sales classes, Other Public Authorities (OPA), Interdepartmental, and Street and Highway Lighting are all related to the housing or customer forecasts by division. Sales to OPA consist of electricity used for water and sewer pumping in the Albuquerque, Belen and Deming Divisions, and are forecast as a ratio to total housing units. Interdepartmental sales in the Santa Fe and Las Vegas divisions are for electricity used by the water departments and are based on ratios to the total number of electric customers (residential plus commercial). Interdepartmental sales in the Albuquerque division are for energy used by PNM office buildings and plant construction, and are forecast exogenously. Street and Highway Lighting requirements are forecast by a ratio to residential customers in each division.

The Load Forecasting System also contains a component for the City of Gallup which is PNM's only full requirements resale customer. This customer's electrical use is similar to PNM's jurisdictional sales. It is therefore included in PNM's base system. Sales are modeled as a function of the price of electricity and total employment in the Gallup area. The estimated equations of the econometric model are contained in the report entitled "1981-2001 Forecast of Energy Sales and Peak Demands."

The long-term assumptions on economic growth and energy prices are also summarized in the report, "1981-2001 Forecast of Energy Sales and Peak Demands." In general, the specific variable projections are developed outside of the Load Forecasting Section. The price of electricity is projected by the Financial Planning Department to average a real rate of increase of 2.5 percent per year through 1985, and then to decline in price relative to other goods and services at varying rates through the end of the century. The price of natural gas as projected by an independent consultant will continue to increase at a moderate rate through 1985, and will accelerate rapidly for a few years immediately following deregulation. Relative prices for these two fuels are projected to be equal in 1991. It is projected that slightly over 50 percent of new residential construction will be all electric by the year of price parity, and that 67 percent of all new electric homes will have some solar application.

Population growth in PNM's service area is projected to be near the 1970s rate of 3.0 percent per year through 1990, as migration into the sunbelt continues. Employment will also continue to increase at high rates of 4 percent to 5 percent per year and participation in the active work force will increase from 44 percent of the total population in 1981 to 52 percent of total population by 2001. Per capita personal income is forecast to grow at a steady rate of 2.5 percent per year through the end of the century.

Forecast Validation

The econometric model is an efficient tool for identifying the demand for electricity under a certain set of circumstances. It takes the approach of estimating the impact of measurable quantities on the market for electricity. When an econometric model is used for forecasting, the implicit assumption is made that the structure of the market will be the same in the future as it was in the past. Until recently, this was a fairly good assumption. However, events in the past few years indicate that the structure of the market may change dramatically in the future. The rapid increases in energy prices (including electricity) have altered the public's attitude toward energy, and have made our society more conservation conscious. Irreversible decisions, such as investments in conservation (building insulation, load management systems) will permanently alter the consumer's response to changing energy prices. Future moratoriums on natural gas supplies could also impact the future market for electricity. The econometric model is simply not equipped to react to these types of impacts.

In view of these complexities, an alternative approach was taken to validate the econometric forecast. This exercise involved using the Load Management Model (LMM), which is a disaggregated end-use model of the residential sector, to approximate structural changes in the demand for electricity. An end-use model takes the approach of estimating energy use per appliance from engineering data. It combines usage patterns with saturation rates for each appliance, and aggregates to total class sales.

Initially, a sensitivity analysis was performed on the econometric model with respect to the various elasticity values. In the late 1980s, PNM is forecasting decreasing electric rates in real terms; however, certain conservation measures taken by consumers will lesson their response to decreasing rates. Currently it is estimated that about 40 percent of the conservation measures taken are permanent in nature, (such as adding insulation). Additionally, it is felt that once more stringent building codes are adopted they will not be rescinded. Therefore, the response to electric price was decreased by 25 percent in the years in which the real electric price is forecast to decrease. Secondly, the response to natural gas price was lagged by 25 percent in each of the three years immediately following deregulation (1986-1988). This was done to reflect lags in people's perceptions concerning rapid price increases, and to reflect investment constraints that will limit the ability to convert from natural gas to electricity very quickly. Finally, the response to income was lowered in all years by about 25 percent in view of evidence that as individual wealth increases, there is more of a tendency to invest in conservation (i.e., more efficient appliances and housing), thereby using less energy. These adjustments were also made in the commercial class to reflect similar energy use patterns. The net result of these sensitivity runs was a sales forecast that was 17 to 20 percent lower by 1990 for these two classes.

The second step in the validation exercise was to use technical data from the Load Management Model to verify some of the structural changes to the demand for electricity that were approximated by the sensitivity analysis. In order to accomplish this, the residential model was restructured to identify customer groups by major end-use on a total Company basis. Historical and forecasted saturation data for air-conditioning and heating types were taken from Market Research and Load Management. Energy use for electric space heating, including backup for solar heat, and refrigerated air-conditioning were also taken from the Load Management Model. The unadjusted econometric model was used to forecast average use for conventional (gas heat) customers exclusive of refrigerated air-conditioning. Based on the same customer forecast as the previous runs, this forecast was slightly higher than the modified econometric results described in Step 1.

The final step in the validation exercise was to use the LMM to examine impacts that had not been specifically captured by disaggregating the econometric model into end-use categories. The LMM takes a pure engineering approach, and does not allow for price or income impacts. There were two scenarios specifically treated by the LMM--increased appliance efficiencies and improved building standards. A base case was first run using the same customer forecasts, penetration rates and energy use for heating and cooling as was used in the econometric model in Step 2. The next two runs reduced energy requirements due to improved efficiencies and building codes. These results were overlaid on the econometric end-use forecast by subtracting the net energy reduction from the forecast in Step 2. This final result was within 2 percent of the modified econometric forecast in Step 1.

From this exercise we were able to conclude that there will almost certainly be structural changes to the underlying market for electricity, and that the reduced sensitivity of the econometric model reasonably reflects these changes. By specifically modeling conservation impacts in the residential sector, we felt reasonably comfortable inferring similar responses in the commercial class. Therefore, reduced responses to energy prices were incorporated into the commercial class forecast as well.

Class Contributions to Peak Demand

Following the reconcilation of class sales and customer forecasts, the Load Forecasting Section prepares the forecast of seasonal peak demands. The seasonal peak demands are calculated by methods developed under the same philosophy as for the sales forecast. Forecasting demand by the various components, rather than total load, will result in a more detailed and accurate forecast. This component forecast of demands is possible because of the load survey data gathered and analyzed by the Load Research Section. PNM has had an extensive load research program since 1973. The data from some sample customers and other sources of demand data have proven to be accurate and consistent over the past seven years. The use of class or component system coincident load factors also provides a sound link to the sales forecast.

Because the demands of the resale customers are determined by contracts, this component of demand is separated from the total system demand leaving a base demand to be forecasted. This base demand consists of several classes of customers which together account for all retail sales and the City of Gallup, the one resale customer to whom PNM supplies total requirements. The seasonal base peak demands are forecast by component using the forecasted energy sales and system coincident load factors. The current method allows us to estimate the impacts of growth of particular components on system peaks. The entire process is detailed in the following paragraphs.

First, historical load factors are developed from historical class and component demands at the time of system peak. Sample load survey data provides typical customer profiles on the day of system peak by rate class for the residential and small and general power classes. These are adjusted by the number of customers and allocated to commercial and industrial categories where appropriate. Demand data for other users (large power, lighting, water and sewer pumping) is obtained from a census of actual meter recordings for each customer.

Once the historical class demands are determined, system coincident load factors are calculated, based on the annual energy sales to that class of customer. An analysis of the historic load factors results in projected load factor values for each forecast component.

The classes have exhibited relative stable load factors over the five years for which data has been available. Projected load factors for these classes are generally based on the five year historical average.

Once the component load factors have been established, they are used in the following equation.

$$\frac{\text{class energy for year (MWh)}}{\text{load factor x hours in one year}} = \text{class peak demand (MW)}$$

This calculation results in the seasonal demand for each class at the time of system peak. This step is repeated for each year of the forecast.

System Demands and Energy Requirements

The previous sections have discussed the methods used to forecast energy sales and peak demand contributions for PNM's base system. Three other components are added to determine PNM's total system requirements and system peaks. These are: load management impacts, sales and demands for other firm resale customers, and system energy and demand losses. These items are treated at the total system level, and both energy and demand are generally treated at the same time. A discussion of each is provided below.

Load Management

PNM's load management estimates are expressed as likely megawatt reductions to summer and winter base system peaks in each year of the forecast period. These reductions are based on the assessment of the Load Management Section as to likely customer responses to time-of-use rates and the direct load control of major appliances. These responses include changes in demand resulting from changes in the appliance mix (fewer refrigerated air conditioners, more solar water heating) as customers respond to TOU rates. Although these programs are evaluated with respect to both energy and demand impacts, the change in energy sales was determined to be negligible.

The load management programs are evaluated for their impacts on each customer class, although they are shown in the forecast at the level of system demand. PNM possesses the most reliable and detailed data on appliance usage in the residential sector. These data come from a variety of sources including Load Research, Market Research, and other utilities. The Load Management Model is used to evaluate changing appliance characteristics and the effect of different load management strategies over time. These impacts are applied to the "base case" residential forecast that resulted from joint modeling efforts between

Load Management and Load Forecasting. The major causes of demand reductions at the system peak hour will be customer responses to time-of-use rates by shifting their appliance use in the short run, and by installing different heating, cooling and water heating systems in the long run. Extensive research into the life-cycle costs of competing heating and cooling technologies was used to determine different appliance mixes before and after TOU rates.

The commercial/industrial sector also received extensive review. Responses to TOU rates were based on responses seen elsewhere in the country. There is limited detailed component load data available for this sector at present.

Direct load control is also included as a supplement to TOU rates beginning in 1985. A higher than expected response to the TOU rate structure could eliminate the need to initiate control. The levels presently projected represent a fairly aggressive program.

The load management estimates and programs are reviewed in detail in a separate volume prepared by the Load Management Section.

Other Firm Resale

The projections for peak loads and energy requirements for the other firm resale customers are derived by the Power Contracts Section of the System Planning Department and by the Power Operations Department. Since these customers also obtain power from other sources, their load on PNM's system is somewhat atypical of PNM's native load. Therefore, they are modeled individually. These customers are: Community Public Service Company (CPS), the Department of Energy at Los Alamos (DOE), Plains Generation and Transmission Cooperative (PGT), and the City of Farmington. The current projections for these resale customers are described in the following paragraphs.

The demand projection for CPS was taken to be CPS' contracted demand. Beyond 1987, PNM holds 91 MW (the current contract maximum) to be the maximum capacity that PNM will supply CPS until any amendments to the Main Power Agreement are executed. The energy consumption was projected based on CPS' historical requirements from PNM.

Demand values for DOE are taken from DOE's most recent Appendix "A", its contracted values, with a 2 MW downward adjustment in 1985 to reflect the expressed intent of DOE. The energy projection was based on DOE's historical consumption and the assumptions: (1) that PNM energy would remain less expensive than DOE's gas-fired generation, and (2) that the maximum monthly load factor available under DOE's contract with PNM will remain 126 percent of contracted demand, until December 1983 when the monthly load factor will be reduced to 100 percent.

The projection for PGT was also taken to be its contracted demands. The energy projection was based on PGT's historical consumption with the assumption that the maximum load factor available under its contracts with PNM will remain 100 percent.

Demand values for the City of Farmington were derived from an analysis based on the most recent R. W. Beck load forecast for the City and on subsequent discussions with city officials. The City's own generation, WAPA entitlement, 40 MW participation in San Juan Unit 4, and a 20 percent installed reserve criterion were built into the analysis. The City's ability to reduce its reserved demand below 10 MW in 1983 and 1984 was negotiated as part of the City's proposed participation in Unit 4. Farmington's energy requirement is based on a 95 percent load factor for the reserved demand years of 1981 and 1984 and 70 percent for all other years. These energy projections are based on an evaluation of historical patterns, contractual requirements, projections by PNM, and discussions with the City.

Demand and Energy Losses

The demand and energy losses contain two distinctly different components: bulk transmission losses; and subtransmission and distribution losses and Company use.

The bulk transmission losses (230 kV and above) are estimated by the Technical Services Section of the Resource Development and Technical Services Department. Basically, the peak demand losses are calculated by obtaining loss information from power flow studies and multiplying the losses by the ratio of PNM imports from remote generation stations to total imports from the points of generation. The energy losses are then calculated by using probabilistic techniques to establish the relationship between peak demand losses and average demand losses. Load flow studies were performed for 1982 and 1990. For years where power flow studies are not available, interpolative or extrapolative methods are used to estimate the missing information.

Subtransmission and distribution losses and Company use are treated as a single component. This is forecast by applying constant ratios to base sales and base demands including load management. The ratios, estimated from historical data, are 4.6 percent for other energy losses including Company use, 7.2 percent for summer peak losses, and 6.0 percent for losses on December peak.

The previous paragrpahs have reviewed the individual forecast components that are integrated to form the official Company forecast of energy requirements and peak demands. The emphasis in corporate review is placed on the ten-year sales forecast. Once this forecast is approved, the Load Forecasting Section develops a 20 year sales projection based on econometric results matched to the ten-year corporate forecast and also develops seasonal peak demand projections from class and component load factors applied to the forecast of electric sales. In addition, high and low scenarios are constructed around the 20 year base case projections using the econometric forecasting system. These are developed by examining alternative fuel price and economic variable projections by means of the econometric Forecasting System. Load growth scenarios are also constructed to evaluate potential large industrial loads. These industrial loads are modeled outside of the econometric system, which cannot realistically model potential future loads of a magnitude two to three times that which is reflected in the historical base industrial data base. Another example of a potential load that cannot be captured by the econometric model is the NME merger. The high/low forecasts, the potential industrial development scenario, and the long-range planning scenario are discussed in the following paragraphs.

High/Low Scenarios

High/low forecast scenarios are developed around the 20 year base case projection. The corporate forecast of energy sales and peak demands is representative of PNM's best judgment concerning future changes in the causal variables underlying electric load growth. However, load forecasts are based on projections of many different variables such as population, employment, income, price indices, fuel prices, and technological change. Futhermore, forecasts are needed for planning horizons of 20 years or more. Thus, it is desirable to develop a number of forecasts based on differing assumptions in order to account for some of the uncertainty implicit in any single forecast. The high/low scenarios establish an "envelope" around the base case reflecting upper and lower limits to growth in population, income, employment, and fuel prices over the forecast period.

Scenarios Assumptions

The Bureau of Business and Economic Research (BBER) at the University of New Mexico developed high and low scenarios in addition to base case scenarios for growth in per capita personal income, population, household size, and commercial and industrial employment for each of PNM's operating divisions. These economic scenarios are documented in the report entitled "1981-2001 Forecast of Energy Sales and Peak Demands."

The growth rates for the price of electricity are the same for all three scenarios through 1991. After 1991, electric price. is forecasted to grow at 1 percent less than the rate of inflation in the high scenario and at 1 percent greater than the rate of inflation in the low scenario. Electric price is projected to grow at the rate of inflation after 1991 in the base case.

Natural gas price scenarios that reflect different price deregulation schedules were developed by Dr. Al Parker at the University of New Mexico. These were input into the model to develop the high/low scenarios.

Different mining sales forecasts were developed for each of the scenarios by the Planning and Resources Mining Task Force. The impacts of Load Management programs were varied in the scenarios. The high electric sales forecast reflects only half the MW reduction shown in the base case. The low electric sales forecast contains a MW reduction equal to 125 percent of the base case reduction.

The methodology used to develop the high/low scenarios is consistent with the methodology underlying the base case. That is, the scenarios were developed by means of the Load Forecasting System wherein the econometric portion of the model estimates sales to the residential, commercial, and Albuquerque area base industrial classes. The scenarios also reflect high/low growth assumptions in the mining and Kirtland Air Force Base components of industrial load. Sales to the smaller classes (other public authorities, Street and Highway Lighting, and interdepartmental), are estimated in relation to the residential and commercial customer forecasts in each scenario. Class coincident peak demands are calculated by applying the component load factors used in the base case forecast to the high/low projections of class energy sales.

Industrial Growth Potential in New Mexico

The fourth load growth scenario reflects the impacts of potential industrial growth in the state of New Mexico. Some half dozen industrial firms have contacted PNM concerning future service for new facilities. Their potential future loads must be evaluated in PNM's load studies. Among the factors that attract firms to New Mexico are the quality of life and the availability of electrical power.

The expected loads from potential, future industrial customers are input to the model rather than estimated by the econometric model. This is so because the econometric model projects future industrial loads on the basis of the historical industrial base which is of a magnitude two to three times smaller than the projected industrial market with the addition of these potential industrial customers. These additional industrial customers could increase the demand on PNM's system by 1,000 MW over the 1983 through 1990 period. These loads are superimposed over the baseline forecast (official ten-year forecast and the corresponding 20 year projections). In addition to the potential industrial customers, this scenario reflects accelerated natural gas deregulation to 1982.

Planning Scenario

The fifth scenario, labeled "planning scenario," reflects the middle-line projection of the multiple scenarios that were designed to consider a range of economic growth, including the potential impact of major industrial activity and accelerated natural gas deregulation. This scenario reflects the energy requirements that would be placed on PNM from a strong and continued rate of economic growth in New Mexico. PNM believes this is a realistic scenario upon which to develop prudent long-term system expansion plans which afford PNM the ability to meet the energy requirements of a viable growing New Mexico economy.

The planning scenario was developed by averaging the Load Growth Document projections and the high scenario projections. The primary use of this estimate is for generation planning for 1990 and beyond. Because of long lead times (ten or more years) to bring on line new, economic coal-fired units, it is necessary to plan generation to be able to meet a more optimistic load forecast. The plans can be reduced, if necessary, at a later date when we have more confidence in the forecasts and before significant generation expenditures are required. But, we are unable to accelerate the plans if we have forecasted too low. Planning for strong and sustained economic activity will afford PNM the ability, at minimal cost, to meet the electrical energy requirements of such an economy should it materialize.

The next section summarizes the results of the five load growth scenarios discussed above.

Summary of Results

This section reviews the forecasts of system peak demands, energy requirements, and load factors resulting from the five load growth scenarios discussed in the previous section. The forecast results are presented in Tables 1 through 5 and Figures 1 and 2.

NME

All five of the scenarios discussed in this paper reflect the proposed merger between PNM and New Mexico Electric that was announced on November 18, 1980. PNM's stockholders approved the merger with NME on April 28, 1981. The shareholders of Estacado, Inc., NME parent corporation, approved the merger on April 16, 1981.

NME presently provides electrical service to southeastern New Mexico, including the cities of Hobbs, Eunice, and Jal. The total customers served by NME is approximately 18,900. The projected annual peak demands and energy requirements for NME produced by Stone and Webster were added to each scenario. The NME loads are the same in all scenarios. The results of these scenarios are discussed below.

May 27, 1981 Load Growth Document

Table one contains the projections from the May 27, 1981, Load Growth Document plus projected loads for New Mexico Electric. System peak demand increases from 1,063 MW in 1981 to 2,700 MW in 2001, a compound annual average growth rate of 4.77 percent. System energy requirements range from 6,597 GWh in 1981 to 17,014 GWh in 2001, an annual average rate of growth of 4.85 percent. The load factor increases for the first three years and then stabilizes at around 72 percent over the rest of the forecast period.

The Load Growth Document is an integrated forecast that reflects the operating divisions near term projections (through 1983) and the long-range projections developed by the Load Forecasting Section. The residential and commercial long-range sales projections reflect a modification to the various elasticity values in the econometric model with respect to fuel prices and income. Without these revisions, the commercial and residential sales forecasts would have been almost 20 percent higher. These modifications are discussed in detail in the section entitled "Forecast Validation."

High Scenario

Table 2 contains the projections from the high scenario constructed around the May 27, 1981 Load Growth Document and corresponding 20-year forecast plus projected loads for NME. This scenario was developed by inputting the high economic growth projections from the Bureau of Business and Economic Research and the high scenario natural gas projections from Dr. Parker's study in the econometric model.

System peak demands are projected to grow an average 6.85 percent per year, from 1,098 MW in 1981 to 4,095 MW in the year 2001. By 1990 the high scenario peak is 16 percent higher than the Load Growth Document peak. System energy requirements range from 6,733 GWh in 1981 to 24,042 GWh in 2001, a compound annual average growth rate of 6.57 percent. The load factor is seen to decrease over the forecast horizon, from 70.58 percent in 1981 to 67.01 percent in 2001.

Low Scenario

Table 3 contains the projections from the low scenario constructed around the May 27, 1981, Load Growth Document and corresponding 20-year forecast, plus projected loads for NME. Like the high scenario, these projections were developed by inputting the BBER's low economic growth projections and Dr. Parker's low natural gas scenario in the econometric model.

System peak demands are projected to grow 3.47 percent per year. In 1990, the low peak projection is 9.45 percent below the Load Growth Document projection. The lower band increases to 23 percent by the year 2001. The system load factor is shown to increase from 71.03 percent in 1981 to 76.19 percent in 2001.

Potential Industrial Growth Scenario

Table 4 contains the projections from the potential industrial growth scenario. This scenario is the May 27, 1981, Load Growth Document plus loads from NME, with an explicit adjustment for potential industrial customers. In addition, this scenario reflects accelerated natural gas degregulation to 1982.

System peak demand in 1990 is equal to 2,681 MW, an increase of 946 MW or 55 percent over the Load Growth Document projection of 1,735 MW for 1990. Peak demands are forecasted to grow an average 6.52 percent per year, from 1,063 MW in 1981 to 3,760 MW in 2001. The load factor stays around 71 or 72 percent over most of the forecast period.

Planning Scenario

Table 5 contains the results of the planning scenario, which is an average of the May 27, 1981, Load Growth Document projections and the high scenario projection plus NME loads. It reflects the range of load growth indicated by all five scenarios.

System peak demands are projected to grow an average 5.92 percent per year, from 1,076 MW in 1981 to 3,398 MW in 2001. In 1990, the planning scenario peak demand is 136 MW or 7.8 percent above the Load Growth Document peak projection for 1990. This is increased to 698 MW or 25.9 percent by the year 2001.

Energy requirements are projected to grow from 6,665 GWh in 1981 to 20,528 GWh by 2001. This is equal to a 5.79 annual average rate of growth compared to the Load Growth Document forecast of energy requirements projected to grow at 4.85 percent per year. The system load factor holds steady at around 70 percent over most of the forecast period.

Figures 1 and 2 graphically depict the forecasts of system energy requirements and peak demands, respectively, from all five scenarios.

Conclusions

This report reviews the load growth studies conducted by PNM to determine need for electrical power over the next two decades. A distinction is drawn between the budgeting and planning process at PNM since these processes require different types of supporting load growth analyses. The ten-year Load Growth Document forecast is applied in the budgeting process, while the planning process necessitates the development of 20- to 30-year load forecasts, high and low load growth scenarios for sensitivity analyses, and additional load scenarios that take into account potential specific new loads such as the large industrial firms and the NME merger.

Long-range planning is conducted to ensure that PNM can fulfill its obligation to provide its customers with an adequate and reliable source of electricity at the lowest reasonable cost and its shareholders with a reasonable return on their investment. Plans for capital expansion are constructed so that additions to plant will match within technical, engineering, and economic constraints and the projected loads of the system while providing an adequate reserve margin. The planner must aknowledge the possibility of future load growth exceeding the Load Growth Document projections and that future reserve margins may well have to exceed 20 percent to be deemed adequate.

The "planning scenario" from which the need for power was ascertained is indeed higher than the Load Growth Document forecast. Long-range planning conducted from a probable and realistic load growth scenario that reflects sound, steady economic growth in the state of New Mexico is both prudent and necessary.

TABLE 1

PNM 1981 Load Growth Document

Year	Peak Demands	Energy Requirements	Load Factors
1981	1,063	6,597	70.84
1982	1,106	7,101	73.29
1983	1,093	7,198	75.18
1984	1,097	7,020	73.05
1985	1,183	7,365	71.07
1986	1,280	7,979	71.16
1987	1,403	8,763	71.30
1988	1,536	9,613	71.44
1989	1,641	10,312	71.73
1990	1,735	10,936	71.95
1991	1,795	11,332	72.07
1992	1,860	11,850	72.73
1993	1,942	12,333	72.50
1994	2,031	12,872	72.35
1995	2,124	13,437	72.22
1996	2,217	14,014	72.16
1997	2,306	14,568	72.12
1998	2,399	15,144	72.06
1999	2,495	15,737	72.00
2000	2,596	16,365	71.96
2001	2,700	17,014	71.93

Source: PNM's May 27, 1981, Load Growth Document plus project loads for New Mexico Electric.

TABLE 2

High Scenario

Year	Peak Demands	Energy Requirements	Load Factors
1981	1,089	6,733	70.58
1982	1,156	7,321	72.30
1983	1,213	7,784	73.26
1984	1,252	7,816	71.26
1985	1,341	8,147	69.35
1986	1,452	8,814	69.30
1987	1,585	9,607	69.19
1988	1,721	10,428	69.17
1989	1,864	11,281	69.09
1990	2,006	12,124	68.99
1991	2,119	12,785	68.88
1992	2,246	13,626	69.26
1993	2,399	14,477	68.89
1994	2,566	15,425	68.62
1995	2,749	16,462	68.36
1996	2,946	17,576	68.11
1997	3,139	18,673	67.91
1998	3,350	19,862	67.68
1999	3,578	21,139	67.44
2000	3,818	22,535	67.38
2001	4,095	24,042	67.02

PNM's high load growth scenario constructed around the "base case" Load Growth Document forecast plus projected loads for New Mexico Electric.

TABLE 3

Low Scenario

Year	Peak Demands	Energy Requirements	Load Factors
1981	1,051	6,540	71.03
1982	1,073	6,945	73.89
1983	1,047	6,944	75.71
1984	1,042	6,731	73.74
1985	1,103	6,927	71.69
1986	1,175	7,436	72.24
1987	1,282	8,147	72.54
1888	1,409	8,968	72.66
1989	1,502	9,628	73.17
1990	1,571	10,147	73.73
1991	1,616	10,469	73.95
1992	1,651	10,834	74.91
1993	1,697	11,132	74.88
1994	1,751	11,498	74.96
1995	1,797	11,817	75.07
1996	1,849	12,186	75.24
1997	1,894	12,497	75.32
1998	1,943	12,860	75.56
1999	1,987	13,183	75.74
2000	2,032	13,528	76.00
2001	2,080	13,883	76.19

Source: PNM's low scenario constructed around "the base case" Load Growth Document forecast plus projected loads for New Mexico Electric.

TABLE 4

Potential Industrial Growth Scenario

Year	Peak Demands	Energy Requirements	Load Factors
1981	1,063	6,599	70.87
1982	1,116	7,160	73.24
1983	1,181	7,696	74.39
1984	1,387	8,815	72.55
1985	1,492	9,276	70.97
1986	1,996	12,550	71.78
1987	2,100	13,227	71.90
1888	2,261	14,289	72.14
1989	2,353	14,899	72.28
1990	2,681	17,045	72.58
1991	2,737	17,395	72.55
1992	2,796	17,880	73.00
1993	2,884	18,361	72.68
1994	2,965	18,837	72.52
1995	3,059	19,395	72.38
1996	3,165	20,023	72.22
1997	3,269	20,648	72.10
1998	3,382	21,327	71.99
1999	3,501	22,042	71.87
2000	3,626	22,796	71.77
2001	3,760	23,595	71.64

Source: PNM's May 27, 1981, Load Growth Document plus projected loads for New Mexico Electric, accelerated natural gas deregulation to 1982, and explicit incremental additions for potential major industrial loads.

TABLE 5

Planning Scenario

Year	Peak Demands	Energy Requirements	Load Factors
1981	1,076	6,665	70.71
1982	1,131	7,211	72.78
1983	1,153	7,491	74.17
1984	1,175	7,418	72.07
1985	1,262	7,756	70.16
1986	1,366	8,397	70.17
1987	1,494	9,185	70.18
1888	1,629	10,021	70.22
1989	1,753	10,797	70.31
1990	1,871	11,530	70.35
1991	1,957	12,059	70.34
1992	2,053	12,738	70.83
1993	2,171	13,405	70.49
1994	2,299	14,149	70.26
1995	2,437	14,950	70.03
1996	2,582	15,795	69.83
1997	2,723	16,621	69.68
1998	2,875	17,503	69.50
1999	3,037	18,438	69.31
2000	3,207	19,450	69.23
2001	3,398	20,528	68.96

Source: The average of the May 27, 1981, Load Growth Document projections and the high scenario projections plus projected loads for New Mexico Electric.

Section Page

B.1 APPLICANT'S ANALYSIS OF NEED B-1

B.2 ADDITIONAL FORECASTS AND SUMMARY B-55

B.3 FINDINGS B-61

B.1
ANALYSIS OF NEED

B.1.1 SUMMARY OF FORECASTS AND PLANNED SUPPLY

PNM's Current System

The Public Service Company of New Mexico (PNM) is an investor-owner electric utility that serves a large part of north-central New Mexico, including Albuquerque, Santa Fe, and other communities. PNM currently serves a total population of about 565,000, of which about 80 percent live in the Albuquerque area [9].

The area served by PNM is growing rapidly, and PNM has experienced growth in sales far above the national average for electric utilities. PNM's summer peak has grown at an average compound annual rate of approximately 7.7 percent, and its total energy sales have grown at a compound annual rate of approximately 8.2 percent over the past 10 years (1971-1980).[a] These rates are higher than the national average for that period. PNM expects that this growth will continue over the next 20 years [9,22].

PNM Forecast Scenarios

As part of its ongoing planning efforts, PNM has developed several forecast scenarios. This is typical of electric utilities, since forecasts must be updated as new information becomes available.

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[a] These percentages include sales for resale. If PNM loads only are considered, the rate is 5.6 percent per year for both energy and power.

PNM's most recent long-range forecasts are contained in its 1981-2001 Forecast of Energy Sales and Peak Demands [22].

The 1981-2001 forecast presents three scenarios for electric growth: a high-growth case, and a low-growth case and a middle case. These three projections are summarized in Tables B-1 and B-2.

For its planning scenario for NMGS, PNM is using the average of the middle and high scenarios, calling this a "strong growth" scenario. The rationale behind using this scenario, which is higher than the middle scenario that PNM uses as its official forecast, is that if the higher scenarios actually occur PNM must have sufficient capacity to meet the higher demand. A fifth scenario has also been generated by PNM to identify the effects of very rapid industrial expansion.

A substantial portion of the demand forecast in any of the scenarios will be served by existing capacity or capacity that is already planned. Table B-3 shows the currently planned capacity for the PNM system. Since PNM's forecasts include demand for New Mexico Electric Company (NME), NME's capacity must be included in PNM's total supply. Table B-4 shows the total capacity projected for a PNM-NME integrated system. Subtracting capacity from demand gives the projected additional capacity needs for the PNM system. This is shown in Tables B-5 and B-6. PNM notes [11] that no attempt is made in the 1982-1988 time frame to account for contractual non-firm loads, the most notable of which is PNM's 236-MW contingent sale to San Diego Gas and Electric Company. Thus, PNM will have less generating reserve in the 1980s than shown in Tables B-5 and B-6.

B.1.2 PNM's FORECASTING METHODOLOGY

The main model used in developing the demand forecasts shown in the statement of need for NMGS was an econometric forecasting model

Table B-1. SUMMARY OF PNM FORECAST SCENARIOS--TOTAL PEAK ELECTRICAL REQUIREMENTS*

Year	PNM & NME Without Reserve	Peak Requirements (MW) Historical[1]	Percent Change from Previous Year[2]
1970	-	-	-
1971	528	634	-
1972	564	677	6.8
1973	613	736	8.7
1974	667	800	8.7
1975	672	806	0.8
1976	726	871	8.1
1977	814	977	12.2
1978	913	1096	14.3
1979	964	1157	5.6
1980	1032	1238	7.0
Average 1970-1980			7.7

Year	Forecast[3] Low	Forecast[3] Middle	Forecast[3] High	Percent Change Low	Percent Change Middle	Percent Change High
1981	1261	1276	1307	1.4	2.6	5.1
1982	1281	1327	1387	2.1	4.0	6.1
1983	1256	1312	1454	<2.4>	<1.1>	4.8
1984	1250	1316	1502	<0.5>	0.3	3.3
1985	1324	1420	1609	5.9	7.9	7.1
1986	1410	1536	1742	6.5	8.2	8.3
1987	1540	1684	1902	9.2	9.6	9.2
1988	1691	1843	2065	9.8	9.4	8.6
1989	1802	1969	2237	6.6	6.8	8.3
1990	1885	2082	2407	4.6	5.7	7.6
Average 1980-1990				4.3	5.3	6.9
1991	1939	2154	2543	2.9	3.5	5.7
1996	2219	2660	3535	2.7	4.3	6.8
1998	2332	2879	4020	2.5	4.0	6.6
Average 1990-1998				2.7	4.1	6.6
Average 1980-1998				3.6	4.8	6.8

Note: < > indicates negative numbers.

*Includes NME, contracted sales and 20% reserve. Does not include contingent sales 1982-1988.

[1] Source: PNM Load-1, Table 2.1-1; NME Load-1, Table 2.2-1; 20% minimum reserve margin added by Woodward-Clyde Consultants (WCC).

[2] Computed by WCC.

[3] Source: Tables B-11, B-12, and B-13.

Table B-2. SUMMARY OF PNM FORECAST SCENARIOS--TOTAL ELECTRICAL ENERGY REQUIREMENTS[*]

	Energy Requirements (GWh)	
Year	Historical[1]	Percent Change from Previous Year[3]
1970	-	-
1971	3003	-
1972	3262	8.6
1973	3437	5.4
1974	3653	6.3
1975	4093	12.0
1976	4469	9.2
1977	5157	15.4
1978	5471	6.1
1979	5938	11.9
1980	6121	3.1
Average 1970-1980		8.2

	Forecast[2]			Percent Change		
	Low	Middle	High	Low	Middle	High
1981	6,540	6,597	6,733	6.8	7.8	10.0
1982	6,945	7,101	7,321	6.2	7.6	8.7
1983	6,944	7,198	7,784	0.0	1.4	6.3
1984	6,731	7,020	7,816	<3.1>	<2.5>	0.4
1985	6,927	7,365	8,147	2.9	4.9	4.2
1986	7,436	7,979	8,814	7.3	8.3	8.2
1987	8,147	8,763	9,607	9.6	9.8	9.0
1988	8,968	9,613	10,428	10.1	9.7	8.5
1989	9,628	10,312	11,281	7.4	7.3	8.2
1990	10,147	10,936	12,124	5.4	6.1	7.5
Average 1980-1990				5.2	6.0	7.1
1991	10,469	11,332	12,785	3.2	3.6	5.5
1996	12,186	14,014	17,576	3.1	4.3	6.6
1998	12,860	15,144	19,862	2.7	4.0	6.3
Average 1990-1998				3.0	4.2	6.4
Average 1980-1998				4.1	5.0	6.6

Note: < > indicates negative numbers.

[*] Includes NME demand and contracted sales. Does not include contingent sales (1982-1988).

[1] Source: PNM Load-1, Table 2.1-3; NME Load-1, Table 2.2-2.

[2] Source: Tables B-14, B-15, and B-16.

[3] Percentages computed by WCC.

Table B-3. PNM EXISTING AND PLANNED CAPACITY (EXCLUDING NMGS AND CONTRACTUAL AGREEMENTS

Year	Total Installed Peak Capacity[a] (MW)	Total Installed Energy Capacity (GWh)	New Units Added
1981	1047	5,175	
1982	1471	7,923[b]	SJGS[c] Unit 4 (432 MW)
1983	1601	8,732	Palo Verde Unit 1 (130 MW)
1984	1731	9,540	Palo Verde Unit 2 (130 MW)
1985	1731	9,540	
1986	1861	10,349	Palo Verde Unit 3 (130 MW)
1987	1861	10,349	
1988	1861	10,349	
1989	1861	10,349	
1990	1861	10,349	
1991	1861	10,349	
1992	1861	10,349	
1993	1861	10,349	
1994	1861	10,349	
1995	1745	9,587[d]	
1996	1745	9,587	
1997	1745	9,587	
1998	1745	9,587	

Source: Ref. 9, Table 2.3-5. Total Energy Capacity Computed by WCC from Reserve Margins Shown in Tables 2.3-4 and 2.1-5.

[a] Does not include contractural resources.

[b] Assumes loss of 8 MW due to SO_2 removal system installation.

[c] San Juan Generating Station.

[d] Assumes Tuscon Electric Power exercises its SJGS Unit 4 buy-back option of 136 MW and PNM purchases 20 MW from the city of Farmington.

Table B-4. PNM-NME EXISTING AND PLANNED CAPACITY (excluding NMGS)

	Peak Power (MW)			Total Energy (GWh)		
Year	PNM Capacity	NME Capacity	Total	PNM Capacity	NME Capacity[a]	Total
1981	1047	184	1231	5,175	786	5,961
1982	1471	184	1655	7,923	786	8,709
1983	1601	184	1785	8,732	786	9,518
1984	1731	184	1915	9,540	786	10,326
1985	1731	184	1915	9,540	786	10,326
1986	1861	184	2045	10,349	786	11,135
1987	1861	184	2045	10,349	786	11,135
1988	1861	184	2045	10,349	786	11,135
1989	1861	184	2045	10,349	786	11,135
1990	1861	184	2045	10,349	786	11,135
1991	1861	184	2045	10,349	786	11,135
1992	1861	184	2045	10,349	786	11,135
1993	1861	184	2045	10,349	786	11,135
1994	1861	184	2045	10,349	786	11,135
1995	1745	184	1929	9,587	786	10,373
1996	1745	184	1929	9,587	786	10,373
1997	1745	184	1929	9,587	786	10,373
1998	1745	184	1929	9,587	786	10,373

Sources: Refs. 9, 22.

[a] Estimated from Ref. 9, Table 2.2-3 by assuming an average capacity factor of 48.8% for NME units.

Table B-5. PNM-NME NET SURPLUS/DEFICIT CAPACITY (MW) (excludes NMGS)

Year	Low Scenario	Middle Scenario	High Scenario
1981	<30>	<45>	<76>
1982	367	328	268
1983	529	473	331
1984	857	791	605
1985	783	687	498
1986	635	509	303
1987	505	361	143
1988	354	202	<20>
1989	243	76	<192>
1990	160	<37>	<362>
1991	106	<109>	<498>
1992	64	<187>	<650>
1993	9	<285>	<834>
1994	<56>	<392>	<1034>
1995	<227>	<620>	<1370>
1996	<290>	<731>	<1606>
1997	<344>	<838>	<1838>
1998	<403>	<950>	<2091>

Data Source: Difference between Table B-4 and Tables B-11, B-12, and B-13. Does not include contingent sales 1982-1988.

Note: < > means demand exceeds capacity.

Table B-6. PNM-NME NET SURPLUS/DEFICIT CAPACITY (GWh) (excludes NMGS)

Year	Low Scenario	Middle Scenario	High Scenario
1981	<579>	<636>	<772>
1982	1764	1608	1388
1983	2574	2320	1734
1984	3595	3306	2510
1985	3399	2961	2179
1986	3699	3156	2321
1987	2988	2372	1528
1988	2167	1522	707
1989	1507	823	<146>
1990	988	199	<989>
1991	666	<197>	<1650>
1992	301	<715>	<2491>
1993	3	<1198>	<3342>
1994	<363>	<1737>	<4290>
1995	<1444>	<3064>	<6089>
1996	<1813>	<3641>	<7203>
1997	<2124>	<4195>	<8300>
1998	<2487>	<4771>	<9489>

Data Source: Difference between Table B-4 and Tables B-14, B-15, and B-16. Does not include contingent sales 1982-1988.

Note: < > means demand exceeds supply.

based on trend analysis using multiple regression. This type of model uses historical data on a set of variables (called "independent variables") which are related to a variable of interest (called the "dependent variable"). By comparing historical data on the independent variables with historical data on the dependent variable, a calculation is done to develop a formula for estimating the level of the dependent variable, given the levels of the independent variables. If forecasts of the values of the independent variables for future years are obtained, then the formula can be used to obtain a forecast for the value of the dependent variable.

PNM's load forecasting methodology is described in detail in Ref. 22. Basically, forecasts of sales are prepared for five customer classes: residential, commercial, industrial, miscellaneous, and the City of Gallup. Each of these forecasts uses different input variables and equations. In addition, the commercial and industrial classes include demands that are forecast independently (e.g., irrigation demand and Kirtland Air Force Base demand). Table B-7 summarizes the models used to forecast total sales. The models are applied separately for each operating division and the results are summed to obtain total sales.

Once the econometric models have been used to compute the total energy sales for each category for each year, it is necessary to compute the peak demand for the system. First, the peak demand for each category is computed using the following formula:

$$\frac{\text{Total sales for category for one year (MWh)}}{\text{Category coincident load factor x hours in one year}} = \text{Category peak demand (MW)}$$

The category coincident load factor (i.e., the ratio of average to peak sales) is computed using historical load factors for each category. In most cases the average load factor was used, except

Table B-7. SUMMARY OF FORECASTING MODELS

Model	Input Variables	Model Equation Form	Separately Calculated Sales
RESIDENTIAL MODEL			
	a. Use per Customer b. Number of Customers	Product	
a. Use per Customer	1. Price of Electricity 2. Price of Natural Gas 3. Per Capita Income 4. Summer Cooling Index 5. Heating Degree-Days	Multiplicative	
b. Number of Customers	1. Population 2. Persons per Household	Multiplicative	
COMMERCIAL MODEL			
	a. Use per Customer b. Number of Commercial Customers	Product	1. Sales to Master-Metere Apartments (input from residential model) 2. Irrigation Sales
a. Use per Customer	1. Price of Electricity 2. Price of Natural Gas 3. Per Capita Income 4. Average Commercial Employment 5. Heating Degree-Days 6. Before/After Embargo	Multiplicative	
b. Number of Commercial Customers	1. Number of Residential Customers	Ratio	

Table B-7. SUMMARY OF FORECASTING MODELS (concluded)

Model	Input Variables	Model Equation Form	Separately Calculated Sales
INDUSTRIAL MODEL			
	a. Albuquerque Sales b. Other Division Sales	Sum	1. Mining Sales 2. USAF Sales
a. Albuquerque Sales Model	1. Price of Electricity 2. Price of Natural Gas 3. Gross National Product 4. Employment	Multiplicative	
b. Other Division Sales	1. Albuquerque Sales	Ratio	
GALLUP SALES MODEL			
	1. Price of Electricity 2. Gallup Employment	Multiplicative	
MISCELLANEOUS SALES MODEL			
a. Sales to Other Public Authorities	1. Total Housing Units (from residential model)	Ratio	
b. Interdepartmental Sales	1. Total Commercial and Residential Customers (from residential and commercial models)	Ratio	
c. Street and Highway Lighting Sales	1. Total Commercial and Residential Customers	Ratio	

where a definite trend seems to occur. Table B-8 summarizes the load factors used for each category.

The total energy sales and peak load forecasts form the major output of the econometric model. Before the forecast is complete, however, several additional components are factored in: firm resale contracts with other electric utilities and communities, bulk transmission losses, subtransmission and distribution losses, and PNM company use.

Firm resale amounts are estimated on the basis of existing contracts and conversations with resale customers. Tables B-9 and B-10 summarize PNM's projected contracted sales. (Sales to the City of Gallup are estimated econometrically in the base forecast and thus are not shown in the tables.) Bulk transmission losses are computed on the basis of power flow studies for the years 1982 and 1990. Next, subtransmission, distribution losses, and company use are computed by applying a constant factor to base sales. Finally, in its statement of need for the NMGS project, PNM has included estimates of demand for NME, since PNM is planning to merge with NME.

In addition to meeting its projected demand, PNM maintains a sufficient reserve margin to assure system reliability. PNM uses a minimum reserve margin of 20 percent over peak demand for planning purposes [9, p. 54]. Reserve margins are generally considered when planning supply of power, not when estimating demand. However, in order to estimate the net need for NMGS, the BLM has added a minimum reserve margin of 20 percent to PNM's demand forecast scenarios to arrive at total capacity requirements. Tables B-11, B-12, and B-13 summarize peak requirements for the three scenarios while Tables B-14, B-15, and B-16 summarize total energy requirements. Table B-17 shows PNM's historical growth for comparison. NME historical requirements are included for comparison with forecasts. NME was independent of PNM during this period.

Table B-8. SUMMARY OF LOAD FACTORS (SUMMER PEAK)

Category	Load Factor (%)
Residential	70.0-73.0
Commercial	57.0
Base Industrial	74.0
Mining	90.0
U.S. Air Force	60.0
Other Public Authorities	57.0
Interdepartmental	57.0
Street and Highway Lighting	0.0
Gallup	77.6-78.4

Source: Ref. 22, Table 20.

Table B-9. PNM PROJECTED CONTRACTED SALES, PEAK DEMAND (MW)

Year	TNP	DOE	FMN	PGT	Total
1981	66	22	25	100	213
1982	69	24	10	125	228
1983	72	25	0	77	174
1984	76	26	5	30	137
1985	79	26	10	30	145
1986	83	27	10	30	150
1987	87	29	12	30	158
1988	91	32	15	30	168
1989	91	34	18	30	173
1990	91	36	21	30	178
1991	91	39	24	30	184
1992	91	42	10	30	173
1993	91	44	10	30	175
1994	91	47	10	30	178
1995	91	49	10	30	180
1996	91	52	10	30	183
1997	91	54	10	30	185
1998	91	57	10	30	188
1999	91	59	10	30	190
2000	91	62	10	30	193
2001	91	64	10	30	195

Sources: 1981-1991 [27]; 1992-2001 [28].

Note: Excludes sales to City of Gallup, which are included in base forecasts.

TNP = Texas New Mexico Power Company.
DOE = Department of Energy at Los Alamos.
FMN = City of Farmington.
PGT = Plains Generation and Transmission Cooperative.

Table B-10. PNM PROJECTED CONTRACTED SALES, TOTAL ENERGY (GWh)

Year	TNP	DOE	FMN	PGT	Total
1981	464	219	157	843	1683
1982	475	260	90	1059	1884
1983	496	266	15	849	1626
1984	522	225	31	435	1214
1985	545	230	57	263	1094
1986	570	241	61	263	1135
1987	598	260	71	263	1191
1988	628	282	88	264	1261
1989	638	302	106	263	1309
1990	638	322	124	263	1347
1991	638	347	143	263	1391
1992	717	369	83	263	1432
1993	717	391	61	263	1432
1994	717	413	61	263	1454
1995	717	435	61	263	1476
1996	717	457	61	263	1498
1997	717	479	61	263	1520
1998	717	500	61	263	1541
1999	717	522	61	263	1563
2000	717	544	61	263	1585
2001	717	566	61	263	1607

Sources: 1981-1991 [27]; 1992-2001 [28].

Note: Excludes sales to the City of Gallup, which are included in base forecast.

Table B-11. PNM TOTAL PEAK REQUIREMENTS (MW) LOW SCENARIO

Year	Base Demand + Total Losses[a]	NME Demand[b]	Other Sales[b]	Subtotal	20% Minimum Reserve[c]	Total
1981	716	122	213	1051	210	1261
1982	718	127	228	1073	215	1288
1983	741	132	174	1047	209	1256
1984	768	137	137	1042	208	1250
1985	816	142	145	1103	221	1324
1986	879	146	150	1175	235	1410
1987	975	150	158	1283	257	1540
1988	1087	154	168	1409	282	1691
1989	1172	157	173	1502	300	1802
1990	1232	161	178	1571	314	1885
1991	1267	165	184	1616	323	1939
1992	1309	169	173	1651	330	1981
1993	1350	172	175	1697	339	2036
1994	1398	175	178	1751	350	2101
1995	1438	179	180	1797	359	2156
1996	1484	182	183	1849	370	2219
1997	1523	186	185	1894	379	2273
1998	1565	190	188	1943	389	2332

[a] Source: Computed from Ref. 22, Table 23, by subtracting other sales.

[b] Source: Table B-12.

[c] Computed by WCC.

Table B-12. PNM TOTAL PEAK REQUIREMENTS (MW) MIDDLE SCENARIO

Year	Base Demand	Total Losses	NME Demand	Other Sales	Subtotal	20% Minimum Reserve	Total
1981	656	72	122	213	1063	213	1276
1982	676	75	127	228	1106	221	1327
1983	710	77	132	174	1093	219	1312
1984	743	80	137	137	1097	219	1316
1985	812	84	142	145	1183	237	1420
1986	893	91	146	150	1280	256	1536
1987	996	99	150	158	1403	281	1684
1988	1107	107	154	168	1536	307	1843
1989	1198	113	157	173	1641	328	1969
1990	1276	120	161	178	1735	347	2082
1991	1323	123	165	184	1795	359	2154
1992	1390	128	169	173	1860	372	2232
1993	1462	133	172	175	1942	388	2330
1994	1539	139	175	178	2031	406	2437
1995	1619	146	179	180	2124	425	2549
1996	1701	151	182	183	2217	443	2660
1997	1778	157	186	185	2306	461	2767
1998	1858	163	190	188	2399	480	2879

Sources: Base demand, total losses and other sales: 1981-1991 from Ref. 22, p. B-9; 1992-1988 from Ref. 28, Table B.

NME demand inferred from Ref. 9, p. 45, and average of Tables B-12 and B-13 subtotals (strong growth scenario) without NME by WCC.

20% reserve margin computed by WCC. Ref. 9, Table 2.3-5, identifies 20% as a minimum reserve.

Table B-13. PNM TOTAL PEAK REQUIREMENTS (MW) HIGH SCENARIO

Year	Base Demand + Total Losses[a]	NME Demand[b]	Other Sales[c]	Subtotal	20% Minimum Reserve[d]	Total
1981	754	122	213	1089	218	1307
1982	801	127	228	1156	231	1387
1983	906	132	174	1212	242	1454
1984	978	137	137	1252	250	1502
1985	1054	142	145	1341	268	1609
1986	1156	146	150	1452	290	1742
1987	1277	150	158	1585	317	1902
1988	1399	154	168	1721	344	2065
1989	1534	157	173	1864	373	2237
1990	1667	161	178	2006	401	2407
1991	1770	165	184	2119	424	2543
1992	1904	169	173	2246	449	2695
1993	2052	172	175	2399	480	2879
1994	2213	175	178	2566	513	3079
1995	2390	179	180	2749	550	3299
1996	2581	182	183	2946	589	3535
1997	2768	186	185	3139	628	3767
1998	2972	190	188	3350	670	4020

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[a] Source: Computed from Ref. 22, Table 24 by subtracting other sales.

[b] Source: NME demand inferred from Ref. 9, p. 45, and average of Table B-12 and B-13 (Strong Growth Scenario) without NME by WCC.

[c] Source: Table B-12. PNM states that the same levels of sales are used for all three scenarios.

[d] Computed by WCC.

Table B-14. PNM TOTAL ENERGY REQUIREMENTS (GWh) LOW SCENARIO

Year	Base Sales + Total Losses	NME Sales	Other Sales	Total
1981	4,100	757	1683	6,540
1982	4,246	815	1884	6,945
1983	4,449	869	1626	6,944
1984	4,640	877	1214	6,731
1985	4,949	884	1094	6,927
1986	5,391	910	1135	7,436
1987	6,019	937	1191	8,147
1988	6,743	964	1261	8,968
1989	7,332	987	1309	9,628
1990	7,785	1015	1347	10,147
1991	8,036	1042	1391	10,469
1992	8,324	1078	1432	10,834
1993	8,608	1092	1432	11,132
1994	8,935	1109	1454	11,498
1995	9,209	1132	1476	11,817
1996	9,538	1150	1498	12,186
1997	9,802	1175	1520	12,497
1998	10,120	1199	1541	12,860

Sources: Base sales and total losses computed by subtracting other sales from Ref. 22, Table 23; NME sales and other sales from Table B-15.

Table B-15. PNM TOTAL ENERGY REQUIREMENTS (GWh) MIDDLE SCENARIO

Year	Base Sales	Total Losses	NME Sales	Other Sales	Total
1981	3,857	300	757	1683	6,597
1982	4,086	316	815	1884	7,101
1983	4,369	334	869	1626	7,198
1984	4,580	349	877	1214	7,020
1985	5,013	374	884	1094	7,365
1986	5,532	402	910	1135	7,979
1987	6,197	438	937	1191	8,763
1988	6,912	476	964	1261	9,613
1989	7,508	508	987	1309	10,312
1990	8,037	537	1015	1347	10,936
1991	8,343	556	1042	1391	11,332
1992	8,760	580	1078	1432	11,850
1993	9,204	605	1092	1432	12,333
1994	9,677	632	1109	1454	12,872
1995	10,169	660	1132	1476	13,437
1996	10,678	688	1150	1498	14,014
1997	11,158	715	1175	1520	14,568
1998	11,661	743	1199	1541	15,144

Sources: Base sales, total losses and other sales: 1981-1991 from Ref. 27, Table A; 1992-2001 from Ref. 28, Table A. NME sales inferred by subtracting average of high and middle scenario (Tables B-15 and B-16) without NME from Ref. 9, Table 2.3.1.

Table B-16. PNM TOTAL ENERGY REQUIREMENTS (GWh) HIGH SCENARIO

Year	Base Sales + Total Losses	NME Sales	Other Sales	Total
1981	4,293	757	1683	6,733
1982	4,622	815	1884	7,321
1983	5,289	869	1626	7,784
1984	5,725	877	1214	7,816
1985	6,169	884	1094	8,147
1986	6,769	910	1135	8,814
1987	7,479	937	1191	9,607
1988	8,203	964	1261	10,428
1989	8,985	987	1309	11,281
1990	9,762	1015	1347	12,124
1991	10,352	1042	1391	12,785
1992	11,116	1078	1432	13,626
1993	11,953	1092	1432	14,477
1994	12,862	1109	1454	15,425
1995	13,854	1132	1476	16,462
1996	14,928	1150	1498	17,576
1997	15,978	1175	1520	18,673
1998	17,116	1199	1547	19,862

Sources: Base sales and total losses computed by subtracting other sales from Ref. 22, Table 24. NME sales and other sales from Table B-15.

Table B-17. PNM HISTORICAL GROWTH, 1971-1980

	Peak Power (MW)					
Year	PNM Requirements[a]	NME[b]	Other Sales[c]	Subtotal[d]	20% Minimum Reserve[e]	Total[e]
1971	443	69	16	528	106	634
1972	473	73	18	564	113	677
1973	514	80	19	613	123	736
1974	549	83	35	667	133	800
1975	547	86	38	672	134	806
1976	584	93	49	726	145	871
1977	620	99	95	814	163	977
1978	680	104	129	913	183	1096
1979	695	109	160	964	193	1157
1980	724	119	184	1032	206	1238

	Total Energy (GWh)			
Year	PNM Requirements[e]	NME[b]	Other Sales[f]	Total[e]
1971	2384	469	150	3003
1972	2602	491	169	3262
1973	2736	523	178	3437
1974	2830	539	284	3653
1975	3229	572	292	4093
1976	3489	604	376	4469
1977	3772	638	747	5157
1978	3781	668	1022	5471
1979	3953	715	1271	5938
1980	3903	719	1499	6121

[a] Computed by WCC with Ref. 9, Table 2.1-6.

[b] Ref. 9, Table 2-2.1.

[c] Ref. 9, Table 2-1.4.

[d] Computed by WCC as sum of Tables 2.1-6 and 2.2-1.

[e] Computed by WCC.

[f] Estimated by WCC from Ref. 9, Table 2-2.1, and projected load factors.

B.1.3 INPUT VARIABLES

The econometric models used by PNM for load forecasts use input data from a variety of sources. Table 6-5 lists the variables and the specific submodels where they are used. These variables are discussed individually below.

Per Capita Personal Income

Per capita personal income (PCPI) data were supplied by the University of New Mexico (UNM) Bureau of Business and Economic Research [29]. The values for PCPI for the Albuquerque SMSA are shown in Table B-18. Similar forecasts were made for Santa Fe, Belen, San Miguel (Las Vegas), and Luna (Deming).

Residential Electric Bill

The amount of a 500-kilowatthour (kWh) electric bill (representing an average residential bill) was forecast using the PNM corporate financial model, based on historical data from PNM Residential Rate Schedules deflated by the consumer price index. The values are shown in Table B-19. Only one forecast was used for this variable.

Price of Electricity for Commercial Customers

The price of electricity in real terms (1967 dollars) for commercial customers was estimated for each division in terms of cents per kilowatthour. Historical data were obtained from PNM financial statements for various years. Forecasted prices were obtained from PNM's corporate financial model. The values for the total PNM service area are shown in Table B-20. Only one forecast was used for this variable.

Table B-18. PER CAPITA PERSONAL INCOME (1967 dollars)

Year	Historical	Percent Change from Previous Year
1970	$2996	-
1971	3143	4.9%
1972	3379	7.5
1973	3420	1.2
1974	3313	<3.1>
1975	3365	1.6
1976	3514	4.4
1977	3642	3.6
1978	3790	4.1
1979	3820	0.8
1980	3681	<3.6>
Average 1970-1980		2.1

	Forecast			Percent Change		
	Low	Middle	High	Low	Middle	High
1981	3768	3773	3785	2.4	2.5	2.8
1982	3857	3867	3892	2.4	2.5	2.8
1983	3948	3964	4002	2.4	2.5	2.8
1984	4041	4063	4116	2.4	2.5	2.8
1985	4136	4165	4232	2.4	2.5	2.8
1986	4234	4269	4352	2.4	2.5	2.8
1987	4334	4376	4475	2.4	2.5	2.8
1988	4436	4485	4602	2.4	2.5	2.8
1989	4541	4597	4732	2.4	2.5	2.8
1990	4648	4712	4866	2.4	2.5	2.8
Average 1980-1990				2.4	2.5	2.8
1991	4758	4830	5004	2.4	2.5	2.8
1996	5340	5470	5750	2.3	2.5	2.8
2001	6000	6180	6610	2.4	2.5	2.8
Average 1990-2001				2.3	2.5	2.8
Average 1980-2001				2.4	2.5	2.8

Note: Income data are for Albuquerque SMSA only.

Source: Ref. 29. Percent changes computed by WCC.

Table B-19. REAL PRICE OF ELECTRICITY FOR A RESIDENTIAL BILL OF 500 MW (1967 dollars)

Year	Historical	Percent Change From Previous Year
1970	10.47	-
1971	10.04	<4.1>
1972	10.27	2.3
1973	10.11	<1.6>
1974	9.74	<3.7>
1975	10.33	6.1
1976	10.42	0.9
1977	11.41	9.5
1978	13.06	14.5
1979	14.20	8.7
1980	13.14	<7.5>
Average 1970-1980		2.3

	Forecast[a]			Percent Change		
	Low	Middle	High	Low	Middle	High
1981		13.54			3.0	
1982		14.69			8.5	
1983		14.34			<2.4>	
1984		14.94			4.2	
1985		14.87			<0.5>	
1986		14.04			<5.6>	
1987		13.25			<5.6>	
1988		12.72			<4.0>	
1989		12.13			<4.6>	
1990		11.88			<2.1>	
Average 1980-1990					<1.0>	
1991	11.76	11.88	12.00	<1.0>	0.0	1.0
1996	11.18	11.88	12.61	<1.0>	0.0	1.0
2001	10.63	11.88	13.26	<1.0>	0.0	1.0
Average 1990-2001				<1.0>	0.0	1.0
Average 1980-2001				<1.0>	<0.5>	0.0

Source: Ref. 22, Table A-5.

1970-1990 Percent changes computed by WCC.

1991-2000 Absolute values computed by WCC.

[a] Low prices used in high scenario and high prices used in low scenario.

Table B-20. REAL PRICE OF ELECTRICITY FOR COMMERCIAL CUSTOMERS (¢/kWh, 1967 dollars)

Year	Historical	Percent Change From Previous Year
1970	1.69	-
1971	1.62	<4.1>
1972	1.65	1.9
1973	1.49	<9.7>
1974	1.42	<4.7>
1975	1.51	6.3
1976	1.56	3.3
1977	1.70	9.0
1978	2.12	24.7
1979	2.36	11.3
1980	2.21	<6.4>
Average 1970-1980		2.7

	Forecast[a]			Percent Change		
	Low	Middle	High	Low	Middle	High
1981		2.35			6.3	
1982		2.58			9.8	
1983		2.54			<1.6>	
1984		2.67			5.1	
1985		2.66			<0.4>	
1986		2.52			<5.3>	
1987		2.38			<5.6>	
1988		2.29			<3.8>	
1989		2.19			<4.4>	
1990		2.15			<1.8>	
Average 1980-1990					<0.3>	
1991	2.13	2.15	2.17	<1.0>	0.0	1.0
1996	2.03	2.15	2.28	<1.0>	0.0	1.0
2001	1.93	2.15	2.40	<1.0>	0.0	1.0
Average 1990-2001				<1.0>	0.0	1.0
Average 1980-2001				<0.6>	<0.1>	0.4

Source: Ref. 22. Percent changes computed by WCC.

[a] Low prices used in high scenario and high prices used in low scenario.

Real Price of Electricity for Gallup Customers

The price of electricity in real terms (1967 dollars) for Gallup customers was estimated in terms of cents per kilowatthour. The historical and forecast values are shown in Table B-21. Only one forecast was used for this variable.

Price of Natural Gas for Residential Customers

The price of natural gas in real terms was estimated for residential customers in terms of the cost of a typical residential monthly usage of 10,000 cubic feet (10 mcf). Separate estimates were made for Gas Company of New Mexico (GASCO), Deming, and Las Vegas customers. Historical data were obtained from the appropriate rate schedules, and the forecasts were prepared by Dr. Alfred Parker of the UNM Economics Department [30]. Table B-22 shows the historical and forecast values for the GASCO service region.

Price of Natural Gas for Commercial Customers

The price of natural gas in real terms was estimated for commercial customers in terms of the cost of a typical monthly use of 125 mcf. Separate estimates were made for GASCO, Deming, and Las Vegas customers, using the same sources as those for residential gas prices. Table B-23 shows the historical and forecast values for the GASCO service region.

Ratio of Industrial Price of Electricity to Price of Gas

The price of electricity in real terms for Albuquerque area industrial users was divided by the cost of natural gas for industrial users with a typical monthly usage of 2500 mcf. Electricity costs were developed from PNM financial statements and the corporate financial model. Natural gas costs were from GASCO rate schedules and the natural gas study by Dr. Alfred Parker [30]. Table B-24 shows the historical and forecast electric prices, Table B-25 shows the

Table B-21. GALLUP PRICE OF ELECTRICITY (Real ¢/kwh, 1967 dollars)

Year	Historical	Percent Change From Previous Year
1970	.64	3.23
1971	.63	-1.56
1972	.61	-3.17
1973	.60	-1.64
1974	.63	5.00
1975	.67	6.35
1976	.67	0.00
1977	.87	29.85
1978	1.04	19.54
1979	1.11	6.73
1980	0.90	-18.92
Average 1970-1980		3.5
	Forecast	**Percent Change**
1981	0.96	6.52
1982	0.98	2.57
1983	0.95	-3.44
1984	0.91	-4.59
1985	0.96	5.53
1986	0.90	-5.38
1987	0.94	4.70
1988	0.87	-7.68
1989	0.87	0.15
1990	0.93	6.25
Average 1980-1990		0.30
1991	0.93	0.00
1996	0.97	1.00
2001	1.02	1.00
Average 1990-2001		1.00
Average 1980-2001		0.6

Source: Ref. 31.

Table B-22. REAL PRICE OF NATURAL GAS FOR RESIDENTIAL CUSTOMERS (GASCO, $/10 mcf 1967 Dollars)

Year	Historical	Percent Change From Previous Year
1970	6.90	-
1971	6.62	<4.06>
1972	7.25	9.52
1973	7.09	<2.21>
1974	7.53	6.21
1975	7.95	5.58
1976	8.53	7.30
1977	10.19	19.46
1978	10.96	7.56
1979	11.43	4.29
1980	10.85	<5.07>
Average 1970-1980		4.6

	Forecast			Percent Change		
	Low	Middle	High	Low	Middle	High
1981	11.07	11.07	11.07	1.99	1.99	1.99
1982	11.47	11.47	12.23	3.63	3.63	10.48
1983	11.88	11.88	16.87	3.60	3.60	37.99
1984	12.28	12.28	18.85	3.40	3.40	11.75
1985	12.86	14.33	19.98	4.76	16.64	6.0
1986	13.65	16.80	21.24	6.07	17.23	6.31
1987	16.40	19.96	22.62	20.21	18.82	6.49
1988	20.35	23.56	24.13	24.04	18.03	6.66
1989	22.08	24.57	25.77	8.54	4.28	6.81
1990	22.65	25.63	27.57	2.55	4.33	6.96
Average 1980-1990				7.6	9.0	9.8
1991	23.24	26.75	29.52	2.56	4.38	7.10
1996	26.38	33.36	42.29	2.6	4.5	7.5
2001	29.98	41.95	61.80	2.6	4.7	7.9
Average 1990-2001				2.6	4.6	7.6
Average 1980-2001				5.0	6.7	8.6

Sources: Middle forecast, Ref. 22. High and low forecasts derived from Ref. 30. Real prices computed by WCC for high and low forecasts from percent changes.

Table B-23. REAL PRICE OF NATURAL GAS FOR COMMERCIAL CUSTOMERS (GASCO, $/125 mcf 1967 Dollars)

Year	Historical	Percent Change From Previous Year
1970	65.03	-
1971	63.03	<3.08>
1972	66.28	5.16
1973	61.40	<7.36>
1974	64.77	5.49
1975	71.41	10.25
1976	80.16	12.25
1977	100.77	25.71
1978	110.54	9.70
1979	113.89	3.03
1980	108.45	<4.78>
Average 1970-1980		5.2

	Forecast			Percent Change		
	Low	Middle	High	Low	Middle	High
1981	110.92	110.92	110.92	2.28	2.28	2.28
1982	115.50	115.50	124.18	4.13	4.13	11.95
1983	120.22	120.22	177.24	4.08	4.08	42.73
1984	124.82	124.82	199.89	3.83	3.83	12.78
1985	131.50	148.17	212.80	5.35	18.71	6.46
1986	140.42	176.37	227.21	6.78	19.03	6.77
1987	171.91	212.47	242.96	22.43	20.48	6.93
1988	216.97	253.61	260.16	26.21	19.35	7.08
1989	236.82	265.12	278.94	9.15	4.54	7.22
1990	243.24	277.27	299.44	2.71	4.58	7.35
Average 1980-1990				8.4	9.8	10.7
1991	249.88	290.08	321.81	2.72	4.62	7.47
1996	285.84	365.55	467.66	2.7	4.7	7.8
2001	326.90	463.62	690.46	2.7	4.9	8.1
Average 1990-2001				2.7	4.8	7.9
Average 1980-2001				5.4	6.7	9.2

Sources: Ref. 22. High and low forecasts from Ref. 30. Real prices computed by WCC from percent changes for high and low forecasts.

Table B-24. REAL PRICE OF ELECTRICITY FOR INDUSTRIAL CUSTOMERS (¢/kWh, 1967 dollars)

Year	Historical	Percent Change from Previous Year
1970	1.46	-
1971	1.40	<4.1>
1972	1.33	<5.0>
1973	1.15	<13.5>
1974	1.07	<7.0>
1975	1.23	15.0
1976	1.25	1.6
1977	1.50	20.0
1978	1.79	19.3
1979	1.64	<8.4>
1980	1.67	1.8
Average 1970-1980		1.4

	Forecast			Percent Change		
	Low	Middle	High	Low	Middle	High
1981		1.79			7.2	
1982		2.02			12.8	
1983		2.00			<1.0>	
1984		2.13			6.5	
1985		2.14			0.5	
1986		2.03			<5.1>	
1987		1.92			<5.4>	
1988		1.85			<3.6>	
1989		1.77			<4.3>	
1990		1.75			<1.1>	
Average 1981-1990					0.5	
1991	1.73	1.75	1.77	<1.0>	0.0	1.0
1996	1.65	1.75	1.86	<1.0>	0.0	1.0
2001	1.57	1.75	1.96	<1.0>	0.0	1.0
Average 1990-2001				<1.0>	0.0	1.0
Average 1980-2001				<0.3>	0.2	0.8

Source: Ref. 22. 1970-1990 percent changes computed by WCC.
1991-2001 absolute values computed by WCC.

Table B-25. REAL PRICE OF NATURAL GAS FOR INDUSTRIAL CUSTOMERS
($/2500 mcf, 1967 dollars)

Year	Historical	Percent Change from Previous Year
1970	949.09	-
1971	919.92	<3.1>
1972	970.03	5.4
1973	910.51	<6.1>
1974	1028.24	12.9
1975	1183.65	15.1
1976	1369.38	15.7
1977	1834.84	34.0
1978	2113.26	15.2
1979	2215.97	4.9
1980	2131.65	<3.8>
Average 1970-1980		8.4

	Forecast			Percent Change		
	Low	Middle	High	Low	Middle	High
1981	2181.10	2181.10	2,181.10	2.32	2.32	2.32
1982	2272.88	2272.93	2,246.33	4.21	4.21	12.16
1983	2367.18	2367.26	3,508.52	4.15	4.15	43.42
1984	2459.46	2459.58	3,691.82	3.90	3.90	12.92
1985	2593.26	2926.15	4,220.53	5.44	19.01	6.53
1986	2771.81	3491.50	4,509.21	6.89	19.28	6.84
1987	3402.52	4214.59	4,824.41	22.75	20.71	6.99
1988	4304.60	5037.70	5,168.87	26.51	19.53	7.14
1989	4701.90	5267.92	5,544.65	9.23	4.57	7.27
1990	4830.58	5511.30	5,954.95	2.74	4.62	7.40
Average 1980-1990				8.5	10.0	10.8
1991	4962.97	5768.12	6,402.76	2.74	4.66	7.52
1996	5682.77	7279.38	9,320.94	2.7	4.8	7.8
2001	6504.93	9242.86	13,781.96	2.7	4.9	8.1
Average 1990-2001				2.7	4.8	7.9
Average 1980-2001				5.5	7.2	9.3

Sources: Ref. 22. High and low forecast percentages from Ref. 30. Forecast prices computed from percentages by WCC.

historical and forecast natural gas prices, and Table B-26 shows the resulting ratios used in the model.

Average Mean Temperatures for June, July, and August

The mean summer temperatures for PNM's service area were obtained from National Oceanic and Atmospheric Administration (NOAA) monthly publications for Albuquerque, Deming, and Santa Fe/Las Vegas. It was assumed that all forecast years would experience the average mean temperature that occurred during the period 1966-1980 (76.35°F for Albuquerque). The historical values for this variable are shown in Ref. 22, Table A-19.

Heating Degree-Days

Heating degree-days are a measure of heating requirements that relates to both the intensity and duration of cold weather. One heating degree-day is one day with an average temperature 1°F less than the base temperature of 65°F. A day with an average temperature of 63°F would be counted as two heating degree-days; 62°F would be counted as three, and so on. Yearly heating degree-days for Albuquerque, Deming, and Santa Fe/Las Vegas were calculated from NOAA publications for the years 1966-1980. The average from this period (4445 heating degree-days for Albuquerque) was used as the projection for all forecast years. The historical values are shown in Ref. 22, Table A-20.

Population

Population for PNM's service area was estimated by the UNM Bureau of Business and Economic Research [29]. Estimates were made for the Albuquerque, Santa Fe, Belen, San Miguel, and Luna areas. Table B-27 shows the population projections for the PNM service area.

Table B-26. RATIO OF INDUSTRIAL PRICE OF ELECTRICITY TO NATURAL GAS (¢/kWh - $/2500 mcf)*

Year	Historical ($\times 10^{-3}$)	Percent Change from Previous Year
1970	1.54	-
1971	1.52	<1.30>
1972	1.37	<9.87>
1973	1.26	<8.03>
1974	1.04	<17.46>
1975	1.04	0.00
1976	.91	<12.50>
1977	.82	<9.89>
1978	.85	3.66
1979	.74	<11.76>
1980	.78	4.00
Average 1970-1980		<6.6>

	Forecast ($\times 10^{-3}$)			Percent Change		
	Low	Middle	High	Low	Middle	High
1981	.821	.821	.821	5.26	5.26	5.26
1982	.889	.889	.826	8.28	8.28	0.61
1983	.845	.845	.570	<4.95>	<4.95>	<30.99>
1984	.866	.866	.577	2.49	2.49	1.23
1985	.825	.731	.507	<4.73>	<15.59>	<12.13>
1986	.732	.581	.450	<11.27>	<20.52>	<11.24>
1987	.564	.456	.398	<22.95>	<21.51>	<11.56>
1988	.430	.367	.358	<23.76>	<19.52>	<10.05>
1989	.376	.336	.319	<12.76>	<8.45>	<10.89>
1990	.362	.318	.294	<3.72>	<5.36>	<7.84>
Average 1980-1990				<7.4>	<8.6>	<9.3>
1991	.357	.303	.270			
1996	.327	.240	.177	<1.7>	<4.6>	<8.1>
2001	.301	.189	.113	<1.6>	<4.7>	<8.6>
Average 1990-2001				<1.7>	<4.6>	<8.3>
Average 1980-2001				<4.4>	<6.5>	<8.8>

Data source: Ratio of Table B-24 to Table B-25. Computed by WCC.

*Not Btu-equivalent.

Table B-27. POPULATION, PNM SERVICE AREA

Year	Historical	Percent Change From Previous Year
1970	423,300	-
1971	438,100	3.5
1972	456,500	4.2
1973	474,100	3.9
1974	488,100	3.0
1975	497,900	2.0
1976	512,200	2.9
1977	526,400	2.8
1978	534,400	1.5
1979	548,600	2.7
1980	565,000	3.0
Average 1970-1980		2.9

	Forecast			Percent Change		
	Low	Middle	High	Low	Middle	High
1981	576,230	576,240	576,300	2.0	2.0	2.0
1982	593,380	593,880	594,200	3.0	3.1	3.1
1983	611,320	612,420	613,200	3.0	3.1	3.2
1984	629,970	631,770	633,100	3.1	3.2	3.2
1985	649,320	651,920	653,800	3.1	3.2	3.3
1986	669,680	672,880	675,700	3.1	3.2	3.3
1987	687,520	694,840	698,600	2.7	3.3	3.4
1988	703,240	718,010	722,900	2.3	3.3	3.5
1989	716,740	742,080	748,600	1.9	3.4	3.6
1990	728,630	764,660	774,400	1.7	3.0	3.4
Average 1980-1990				2.6	3.1	3.2
1991	738,900	785,340	800,300	1.4	2.7	3.0
1996	791,690	876,530	931,200	1.4	2.2	3.1
2001	847,640	973,850	1,088,400	1.4	2.1	3.2
Average 1990-2001				1.4	2.2	3.1
Average 1980-2001				2.0	2.6	3.2

Source: Ref. 29. Percent changes computed by WCC.

Average Household Size

The number of persons per household was estimated by the UNM Bureau of Business and Economic Research [29]. Estimates were made for the Albuquerque, Santa Fe/Belen, San Miguel, and Luna areas. Table B-28 shows the household size trends for the total PNM service area.

Annual Average Commercial and Industrial Employment

Employment within PNM's service area was estimated by the UNM Bureau of Business and Economic Research. Commercial employment was estimated for Albuquerque, Belen, Luna County, San Miguel County, and Santa Fe County. Industrial employment was used for the Albuquerque area only. Total employment was used in the Gallup model. Commercial employment for the total PNM service area is shown in Table B-29, industrial employment for the Albuquerque area is shown in Table B-30, and employment for Gallup is shown in Table B-31.

U.S. Gross National Product

Historical data for the gross national product (GNP) was obtained from various issues of the Survey of Current Business and the U.S. Department of Commerce. Forecasts were obtained from the National Planning Association. All figures were deflated to 1967 dollars using the Producer Price Index. Only a single forecast was made. Table B-32 shows the GNP figures used by PNM.

To summarize the forecasts incorporated in the input variables, Table B-33 compares the rate of change for each variable during the period 1970-1980 and the forecast period of 1981-2001.

B.1.4 ADJUSTMENTS TO FORECAST

An econometric model such as PNM's implicitly contains the assumption that the structure of the market will not change over the

Table B-28. PERSONS PER HOUSEHOLD (PNM SERVICE AREA)

Year	Historical	Percent Change From Previous Year
1970	3.33	-
1971	3.30	<0.9>
1972	3.25	<1.5>
1973	3.19	<1.8>
1974	3.15	<1.3>
1975	3.12	<1.0>
1976	3.06	<1.9>
1977	3.03	<1.0>
1978	2.98	<1.7>
1979	2.95	<1.0>
1980	2.92	<1.0>
Average 1970-1980		<1.3>

	Forecast			Percent Change		
	Low	Middle	High	Low	Middle	High
1981	2.84	2.85	2.88	<2.7>	<2.4>	<1.4>
1982	2.80	2.82	2.86	<1.4>	<1.1>	<0.7>
1983	2.77	2.79	2.84	<1.1>	<1.1>	<0.7>
1984	2.78	2.76	2.82	<1.1>	<1.1>	<0.7>
1985	2.70	2.74	2.80	<1.5>	<0.7>	<0.7>
1986	2.67	2.71	2.79	<1.1>	<1.1>	<0.4>
1987	2.64	2.68	2.78	<1.1>	<1.1>	<0.4>
1988	2.62	2.66	2.77	<0.8>	<0.7>	<0.4>
1989	2.59	2.64	2.75	<1.1>	<0.8>	<0.7>
1990	2.55	2.62	2.74	<1.5>	<0.8>	<0.4>
Average 1980-1990				<1.3>	<1.1>	<0.6>
1991	2.53	2.60	2.73	<0.8>	<0.8>	<0.4>
1996	2.45	2.53	2.70	<0.6>	<0.5>	<0.2>
2001	2.45	2.53	2.70	0.0	0.0	0.0
Average 1990-2001				<0.4>	<0.3>	<0.1>
Average 1980-2001				<0.8>	<0.7>	<0.4>

Source: Ref. 29. Percent changes computed by WCC.

Table B-29. COMMERCIAL EMPLOYMENT (PNM SERVICE AREA)

Year	Historical	Percent Change from Previous Year
1970	117,372	-
1971	124,666	6.2
1972	133,490	7.1
1973	131,638	<1.4>
1974	147,350	11.9
1975	151,719	3.0
1976	160,866	6.0
1977	169,121	5.0
1978	181,899	7.6
1979	190,946	5.0
1980	198,906	4.2
Average 1970-1980		5.4

	Forecast			Percent Change		
	Low	Middle	High	Low	Middle	High
1981	208,910	208,910	208,920	5.0	5.0	5.0
1982	218,840	219,040	219,170	4.8	4.8	4.8
1983	229,350	229,760	230,010	4.8	4.9	4.9
1984	240,260	240,990	241,460	4.8	4.9	5.0
1985	251,880	252,920	253,610	4.8	5.0	5.0
1986	264,190	265,450	266,470	4.9	5.0	5.1
1987	274,690	278,770	280,020	4.0	5.0	5.1
1988	283,380	292,700	294,480	3.2	5.0	5.2
1989	290,790	307,630	309,940	2.6	5.1	5.2
1990	296,960	321,350	325,300	2.1	4.5	5.0
Average 1980-1990				4.1	4.9	5.0
1991	301,840	333,980	340,870	1.6	3.9	4.8
1996	327,560	422,810	419,610	1.6	4.8	4.2
2001	355,080	440,280	516,220	1.6	0.8	4.2
Average 1990-2001				1.6	2.9	4.3
Average 1980-2001				2.8	3.9	4.6

Source: Ref. 29. Percent changes computed by WCC.

Table B-30. INDUSTRIAL EMPLOYMENT (ALBUQUERQUE AREA)

Year	Historical	Percent Change From Previous Year
1970	17,700	-
1971	20,700	16.9
1972	25,900	25.1
1973	27,600	6.6
1974	26,500	<4.0>
1975	25,400	<4.2>
1976	26,500	4.3
1977	28,800	8.7
1978	32,200	11.8
1979	34,000	5.6
1980	33,400	<1.8>
Average 1970-1980		6.6

	Forecast			Percent Change		
	Low	Middle	High	Low	Middle	High
1981	36,100	36,100	36,100	8.1	8.1	8.1
1982	38,700	38,700	38,700	7.2	7.2	7.2
1983	41,500	41,500	41,500	7.2	7.2	7.2
1984	44,500	44,500	44,500	7.2	7.2	7.2
1985	47,600	47,600	47,600	7.0	7.0	7.0
1986	51,000	51,000	51,000	7.1	7.1	7.1
1987	53,900	54,600	54,600	5.7	7.1	7.1
1988	56,300	58,400	58,400	4.5	7.0	7.0
1989	58,300	62,500	62,500	3.6	7.0	7.0
1990	59,900	66,300	66,700	2.7	6.1	6.7
Average 1980-1990				6.0	7.1	7.2
1991	61,200	69,700	70,800	2.2	5.1	6.1
1996	68,300	83,700	92,100	2.2	3.7	5.4
2001	76,000	98,600	118,600	2.2	3.3	5.2
Average 1990-2001				2.2	3.7	5.4
Average 1980-2001				4.0	5.3	6.2

Source: Ref. 29. Percent changes computed by WCC.

Table B-31. TOTAL EMPLOYMENT (GALLUP AREA)

Year	Historical	Percent Change From Previous Year
1970	6,373	-
1971	6,511	2.2
1972	6,694	2.8
1973	6,917	3.3
1974	7,328	5.9
1975	8,101	10.5
1976	8,873	9.5
1977	9,767	10.1
1978	10,973	12.3
1979	10,746	<2.1>
1980	10,409	<3.1>
Average 1970-1980		5.0

	Forecast			Percent Change		
	Low	Middle	High	Low	Middle	High
1981	11,050	11,260	11,260	6.2	8.2	8.2
1982	11,770	12,290	12,290	6.5	9.1	9.1
1983	12,570	13,580	13,580	6.8	10.5	10.5
1984	13,460	14,350	14,350	7.1	5.7	5.7
1985	14,480	15,150	15,150	7.6	5.6	5.6
1986	15,200	16,000	16,000	5.0	5.6	5.6
1987	15,950	16,900	16,900	4.9	5.6	5.6
1988	16,740	17,860	17,860	5.0	5.7	5.7
1989	17,580	18,860	18,860	5.0	5.6	5.6
1990	18,450	19,920	19,920	4.9	5.6	5.6
Average 1980-1990				5.9	6.7	6.7
1991	18,817	20,916	21,613	2.0	5.0	8.5
1996	20,800	26,700	32,500	2.0	5.0	8.5
2001	22,900	34,100	48,900	1.9	5.0	8.5
Average 1990-2001				2.0	5.0	8.5
Average 1980-2001				3.8	5.8	7.6

Source: Ref. 29. Percent changes computed by WCC.

Table B-32. REAL GROSS NATIONAL PRODUCT (BILLIONS OF DOLLARS) (BASE YEAR 1967 = 100)

Year	Historical	Percent Change From Previous Year
1970	889.9	-
1971	933.6	4.9
1972	983.3	5.3
1973	970.0	<1.4>
1974	882.5	<9.0>
1975	874.1	<1.0>
1976	930.2	6.4
1977	978.1	5.1
1978	1016.5	3.9
1979	1024.6	0.8
1980	979.2	<4.4>
Average 1970-1980		1.0
	Forecast	Percent Change
1981	1007.1	2.8
1982	1032.0	2.5
1983	1066.6	3.4
1984	1096.7	2.7
1985	1126.9	2.8
1986	1156.7	2.6
1987	1190.4	2.9
1988	1219.0	2.4
1989	1248.0	2.4
1990	1277.5	2.4
Average 1980-1990		2.7
1991	1307.2	2.3
1996	1465.1	2.3
2001	1633.1	2.2
Average 1990-2001		2.3
Average 1980-2001		2.5

Source: Ref. 22. Percent changes computed by WCC.

Table B-33. SUMMARY OF INPUT VARIABLE RATES OF CHANGE (percent per year)

Variable (Source)	1970-1980 Rate	1980-1991 Rate			1990-2000 Rate		
		Low	Middle	High	Low	Middle	High
Per Capita Personal Income (Table B-18)	2.1	2.4	2.5	2.8	2.4	2.5	2.8
Residential Price of Electricity (Table B-19)	2.3		<0.7>		<1.0>	0.0	1.0
Commercial Price of Electricity (Table B-20)	2.7		<0.3>		<1.0>	0.0	1.0
Gallup Price of Electricity (Table B-21)	3.5		0.3			1.0	
Residential Price of Natural Gas (Table B-22)	4.6	7.6	9.0	9.8	2.6	4.6	7.6
Commercial Price of Natural Gas (Table B-23)	5.2	8.4	9.8	10.7	2.7	4.8	7.9
Industrial Price of Electricity (Table B-24)	1.4		0.5		<0.3>	0.2	0.8
Industrial Price of Natural Gas (Table B-25)	8.4	8.5	10.0	10.8	2.7	4.8	7.9
Ratio Electricity to Natural Gas Price (Table B-26)	<6.6>	<7.4>	<8.6>	<9.3>	<1.7>	<4.6>	<8.3>
Population (Table B-27)	2.9	2.6	3.1	3.2	1.4	2.2	3.1
Persons per Household (Table B-28)	<1.3>	<1.3>	<1.1>	<0.6>	<0.4>	<0.3>	<0.1>
Commercial Employment (Table B-29)	5.4	4.1	4.9	5.0	1.6	2.9	4.3
Albuquerque Industrial Employment (Table B-30)	6.6	6.0	7.1	7.2	2.2	3.7	5.4
Gallup Total Employment (Table B-31)	5.0	5.9	6.7	6.7	2.0	5.0	8.5
Gross National Product (Table B-32)	1.0		2.7			2.3	

forecast period. However, in the case of electricity sales, it is clear that the market structure is changing. Increased prices for natural gas and electricity, more emphasis on conservation, and new technologies such as solar heating and heat pumps are likely to substantially change patterns of electric use over the next two decades.

In order to incorporate some of these changes, PNM made several modifications to its econometric model. The rationale for these changes is given in Ref. 22, pp. 26-29. The modifications were:

1. Lowering the coefficient for the input variable "per capita residential income" in the residential model and in the commercial model

2. Revising electric price forecasts input to the residential and commercial models

3. Revising natural gas price forecasts input to the residential, commercial, and industrial models

4. Weighting 1981 population and employment forecasts with 1980 forecasts.

1. Coefficient for Personal Income

The coefficient for per capita personal income was reduced to reflect an anticipated increase in conservation investments as personal income increases. The residential model coefficient was reduced from 0.617 to 0.464 (a 24.8 percent reduction), and the commercial model coefficient was reduced from 0.515 to 0.493 (a 4.3 percent reduction).

2. Price of Electricity

In those years when the price of electricity is forecast to decline, the amount of the decrease was reduced by 25 percent (40 percent for commercial). This was to simulate the idea that, because of permanent conservation measures, consumers would have a reduced reaction to reduced rates. The specific changes made are shown in Tables B-34 and B-35.

3. Price of Natural Gas

In the years following the forecasted deregulation of natural gas prices (1985-1990), the rate of change in the price of natural gas was revised. This was to simulate delays in customer response to the forecasted price increases. The total percentage increase remains the same over the period, so that no effect is seen after 1991. Table B-36 summarizes these changes for the GASCO service area. Modifications were also made for the Deming and Las Vegas areas.

Note that since these modifications occur before the first NMGS unit would come on line, there is no effect on the forecasts for the NMGS planning period.

4. Population

Population and employment forecasts were reduced by combining them with the 1980 forecasts from the same source (UNM's Bureau of Business and Economic Research [BBER]). The weighting was 60 percent to the BBER 1981 forecast and 40 percent to the BBER 1980 forecast. This modification was made to the variables "population" and "commercial employment" for the Albuquerque and Belen areas and to population for the Santa Fe area. Tables B-37 and B-38 show these modifications for the Albuquerque area.

The net effect of the modifications described above is to reduce the forecasted sales of electricity. In the nominal forecast, the

Table B-34. MODIFICATIONS TO PRICE OF ELECTRICITY, RESIDENTIAL ($/500 kWh, 1967 dollars)

	Original		Modified	
Year	Absolute	% Change	Absolute	% Change
1981	13.54	3.01	13.54	3.01
1982	14.69	8.53	14.69	8.53
1983	14.34	<2.40>	14.43	<1.80>
1984	14.94	4.15	15.02	4.15
1985	14.87	<0.46>	14.97	<0.35>
1986	14.04	<5.56>	14.35	<4.17>
1987	13.25	<5.66>	13.74	<4.25>
1988	12.72	<3.96>	13.33	<2.97>
1989	12.13	<4.70>	12.86	<3.53>
1990	11.88	<2.06>	12.66	<1.55>
1991	12.37	4.13	13.18	4.13
1992	12.15	<1.80>	13.00	<1.35>
1993	11.91	<1.96>	12.81	<1.47>
1994	11.66	<2.12>	12.61	<1.59>
1995	11.39	<2.32>	12.39	<1.74>
1996	11.13	<2.19>	12.18	<1.64>
1997	10.87	<2.31>	11.97	<1.73>
1998	10.60	<2.47>	11.75	<1.85>
1999	10.33	<2.55>	11.53	<1.71>
2000	10.06	<2.65>	11.30	<1.99>
2001	9.79	<2.68>	11.07	<2.01>

Source: Ref. 32. Absolute values computed from percentages by WCC.

Table B-35. MODIFICATIONS TO PRICE OF ELECTRICITY, COMMERCIAL
($/500 kWh, 1967 dollars)

Year	Original		Modified	
	Absolute	% Change	Absolute	% Change
1981	2.35	6.12	2.35	6.12
1982	2.58	9.82	2.58	9.82
1983	2.54	<1.48>	2.56	<0.89>
1984	2.67	5.17	2.69	5.17
1985	2.66	<0.19>	2.69	<0.11>
1986	2.52	<5.43>	2.60	<3.26>
1987	2.38	<5.50>	2.51	<3.30>
1988	2.29	<3.78>	2.46	<2.27>
1989	2.19	<4.29>	2.39	<2.57>
1990	2.15	<1.70>	2.37	<1.02>
1991	2.25	4.70	2.48	4.70
1992	2.21	<1.56>	2.46	<0.94>
1993	2.18	<1.72>	2.43	<1.03>
1994	2.14	<1.89>	2.40	<1.13>
1995	2.09	<2.07>	2.37	<1.24>
1996	2.05	<2.02>	2.35	<1.21>
1997	2.00	<2.16>	2.31	<1.30>
1998	1.96	<2.26>	2.28	<1.36>
1999	1.91	<2.42>	2.25	<1.45>
2000	1.86	<2.48>	2.22	<1.49>
2001	1.81	<2.54>	2.18	<1.52>

Source: Ref. 32. Absolute values computed from percentages by WCC.

Table B-36. MODIFICATIONS TO NATURAL GAS PRICES (GASCO SERVICE AREA)

Year	Original		Modified	
	Absolute	% Change	Absolute	% Change
A. RESIDENTIAL ($/10 mcf)				
1985	14.33	16.64	13.81	12.48
1986	16.80	17.23	15.94	15.42
1987	19.96	18.82	18.87	18.36
1988	23.56	18.03	22.28	18.06
1989	24.57	4.28	24.25	8.86
1990	25.63	4.33	25.74	6.13
B. COMMERCIAL ($/125 mcf)				
1985	148.17	18.71	142.33	14.03
1986	176.37	19.03	166.64	17.08
1987	212.47	20.48	200.10	20.08
1988	253.61	19.35	239.08	19.48
1989	265.12	4.54	261.77	9.49
1990	277.27	4.58	278.84	6.52
C. INDUSTRIAL ($/2500 mcf)				
1985	2926.15	19.01	2821.60	14.26
1986	3491.50	19.28	3310.02	17.31
1987	4214.59	20.71	3982.62	20.32
1988	5037.70	19.53	4766.80	19.69
1989	5267.92	4.57	5222.98	9.57
1990	5511.30	4.62	5566.13	6.57

Source: Ref. 32. Absolute values computed from percentages by WCC.

Table B-37. MODIFICATIONS TO POPULATION, ALBUQUERQUE AREA (thousands)

Year	Original		Modified	
	Absolute	% Change	Absolute	% Change
1981	448.6	1.29	450.4	1.69
1982	462.2	3.03	462.7	2.73
1983	476.6	3.12	475.6	2.79
1984	491.8	3.19	489.0	2.83
1985	507.8	3.25	503.1	2.87
1986	524.7	3.33	517.3	2.83
1987	542.5	3.39	532.2	2.87
1988	561.4	3.48	547.7	2.92
1989	581.4	3.56	564.0	2.97
1990	599.9	3.18	579.4	2.74
1991	617.0	2.85	593.5	2.43
1992	630.4	2.17	605.5	2.02
1993	644.1	2.17	617.7	2.02
1994	658.0	2.17	630.2	2.02
1995	672.3	2.17	642.9	2.02
1996	686.9	2.17	655.3	1.93
1997	701.1	2.06	667.5	1.86
1998	715.5	2.06	679.9	1.86
1999	730.2	2.06	692.6	1.86
2000	745.3	2.06	705.5	1.86
2001	760.7	2.06	718.6	1.86

Source: Ref. 32. Absolute values computed from percentages by WCC.

Table B-38. MODIFICATIONS TO COMMERCIAL EMPLOYMENT, ALBUQUERQUE AREA

	Original		Modified	
Year	Absolute	% Change	Absolute	% Change
1981	167,100	5.16	165,400	4.09
1982	175,800	5.21	174,315	5.39
1983	185,100	5.29	182,699	4.81
1984	194,900	5.29	191,396	4.76
1985	205,400	5.39	200,679	4.85
1986	216,500	5.40	210,432	4.86
1987	228,400	5.50	220,806	4.93
1988	241,000	5.52	231,625	4.90
1989	254,500	5.60	243,100	4.98
1990	266,900	4.87	254,224	4.55
1991	278,200	4.23	262,461	3.24
1992	286,608	3.00	269,022	2.50
1993	295,206	3.00	275,748	2.50
1994	304,062	3.00	282,642	2.50
1995	313,184	3.00	289,708	2.50
1996	322,500	3.00	296,748	2.43
1997	331,401	2.76	303,513	2.28
1998	340,548	2.76	310,434	2.28
1999	349,947	2.76	317,511	2.28
2000	359,605	2.76	324,751	2.28
2001	369,600	2.76	332,155	2.28

Source: Ref. 32. Absolute values computed from percentages by WCC.

rate of growth in total gigawatthour sales declines from 6.3 percent annually to 5.6 percent annually. After comparison with other internal models, PNM concluded that this reduction in growth approximated the reduction that could be expected through conservation in the future. Table B-39 shows the differences between the original and adjusted forecasts for the years 1981-1991.

Comparison with Econometric/End-Use Model

The major purpose of the adjustments described above was to incorporate effects of conservation and changing patterns of electric use that could not be directly captured by the econometric model.

To check whether the modifications were reasonable, PNM compared the adjusted residential model results to the results from a modified version of the residential econometric model called an "econometric/end-use" model by PNM. While the original residential model treats all residential customers the same, the econometric/end-use model subdivides residential customers into categories based on the type of heating and air conditioning used. Six categories of customers were identified:

- Refrigerated air conditioning and gas heat
- Refrigerated air conditioning and and electric heat
- Evaporative air conditioning and gas heat
- Evaporative air conditioning and SMART electric heat
- Evaporative air conditioning and non-SMART electric heat
- Evaporative air conditioning and solar heat

The terms SMART and non-SMART refer to whether the customer meets PNM's "SMART" (Saves Money and Resources Too) standards for quality of home insulation. Estimates of the number of customers in each category and the electric use for each category were made using

Table B-39. COMPARISON BETWEEN UNADJUSTED AND FINAL ECONOMETRIC MODEL FORECASTS (GWh) (TOTAL SALES)

	Unadjusted		Final		Difference	
Year	Absolute	% Change	Absolute	% Change	Absolute	Percent
1981	5,979	-	5,973	-	6	0.1
1982	6,363	9.8	6,343	6.1	20	0.3
1983	6,442	12.4	6,391	0.8	51	0.8
1984	6,293	<2.3>	6,219	<2.7>	74	1.2
1985	6,649	5.7	6,496	4.5	153	2.4
1986	7,375	10.9	7,105	9.4	270	3.8
1987	8,227	11.6	7,827	10.2	400	5.1
1988	9,138	11.1	8,601	9.9	537	6.2
1989	9,912	8.4	9,299	8.1	613	6.6
1990	10,650	7.4	9,956	7.1	694	7.0
1991	11,110	4.3	10,338	3.8	772	7.5

Source: Ref. 31. Percentages and differences computed by WCC.

baseline estimates from the original econometric model and average electric consumption by customer category in 1980. No adjustments were made to the input variables as they were in the original econometric model (see Section 3.4). As shown in Table B-40, the use predicted by the econometric/end-use model was similar to that predicted by the adjusted econometric model.

B.1.5 ESTIMATE OF LOAD MANAGEMENT EFFECTS

An engineering end-use model was used to estimate load management effects. This type of model estimates electric use from the bottom up by developing consumption patterns for each type of end-use appliance (e.g., refrigerator, toaster, washer), estimating the number of each type of appliance in use and summing the patterns to establish the total amount and pattern of electric consumption. An engineering end-use model makes it possible to estimate the impacts of specific conservation measures, such as improving the efficiency of individual appliances. PNM calls this model its Load Management Model (LMM). Its use is described by the applicant in the report Load Management Estimates [33]. The load management model was used to estimate the potential reduction in peak use due to time-of-use rates and direct load control of certain appliances. It was assumed that the time-of-use rates and direct load controls would affect only peak use and would not reduce total consumption, since customers would simply shift their use to times when rates were lower and controls were not in effect.

The estimates of reduction in peak use were subtracted directly from the peak loads forecasted in the adjusted econometric model. The results of this calculation are shown in Table B-41.

Table B-40. COMPARISON BETWEEN ADJUSTED ECONOMETRIC FORECAST AND ECONOMETRIC END-USE MODEL RESULTS

Year	Econometric End-Use Model (GWh)	Adjusted Econometric Model (GWh)	Percent Difference
1981	1142.0	1136.0	-0.5
1982	1176.9	1162.0	-1.3
1983	1265.7	1251.0	-1.2
1984	1330.6	1307.0	-1.8
1985	1446.7	1421.0	-1.8
1986	1607.6	1585.0	-1.4
1987	1801.0	1784.0	-0.9
1988	1999.9	1992.0	-0.4
1989	2164.0	2181.0	+0.8
1990	2323.1	2343.0	+0.9

Source: Ref. 34.

Note: Includes adjustments for appliance efficiency improvements, building insulation improvements, and solar adoption.

Table B-41. ADJUSTMENTS TO MIDDLE FORECAST TO ACCOUNT FOR TIME-OF-USE (TOU) RATES AND DIRECT LOAD CONTROL (DLC) (MW)

Year	Econometric Model Middle Forecast	TOU and DLC Adjustments	Adjusted Base Forecast
1981	669	<13>	656
1982	706	<30>	676
1983	743	<33>	710
1984	779	<36>	743
1985	852	<40>	812
1986	943	<50>	893
1987	1058	<62>	996
1988	1182	<75>	1107
1989	1288	<90>	1198
1990	1381	<105>	1276
1991	1433	<110>	1323
1992	1506	<116>	1390
1993	1584	<122>	1462
1994	1667	<128>	1539
1995	1754	<135>	1619
1996	1843	<142>	1701
1997	1927	<149>	1778
1998	2015	<157>	1858
1999	2107	<165>	1942
2000	2203	<174>	2029
2001	2303	<183>	2120

Sources: 1981-1991 [27]; 1992-2001 [28].

B.2

ADDITIONAL FORECASTS AND SUMMARY

As part of its planning process for NMGS, PNM prepared two additional demand scenarios: a "strong growth" scenario and a "major industrial loads" scenario.

The strong growth scenario is simply the average of the middle and high scenarios described in Section B.1. PNM believes that this is the most prudent scenario for use in planning since it is easier to delay projects if strong growth is planned for but does not occur than it is to speed up projects if low growth is planned for but does not occur.

The major industrial loads scenario represents the middle scenario with two modifications that could increase demand. The first is the use of the high scenario figures for natural gas prices, which include acceleration of natural gas deregulation for 1982. The second is the specific inclusions of certain large industrial loads that could come on line in the 1980s. Table B-42 shows the types of facilities (including their electrical use) that were included in this forecast.

Tables B-43 and B-44 summarize the strong growth and major industrial loads scenarios in terms of demand and net requirements.

Table B-42. POTENTIAL INDUSTRIAL LOADS USED IN MAJOR INDUSTRIAL LOADS SCENARIO

Year	MW	Customer Type
1983	21	Manufacturer
1984	21	Chemical Plant
1984	163	CO_2 Pumping
1986	420	Aluminum Plant
1988	70	Synfuel Plant
1990	250	Aluminum Plant

Source: Ref. 35. Sources indicate these plants represent a "cross-section (judgment) of a portion of the potential loads using the preliminary inservice dates and amounts from 1983 through 1990."

Table B-43. SUMMARY OF "STRONG GROWTH" SCENARIO

Year	Peak Requirements (MW) (+20%)	Net Surplus/ Deficit Power Capacity (MW)	Energy Requirements (GWh)	Net Surplus/ Deficit Energy Capacity (GWh)
1981	1291	<60>	6,665	<704>
1982	1357	298	7,211	1498
1983	1384	401	7,491	2027
1984	1410	697	7,418	2908
1985	1514	593	7,756	2570
1986	1639	406	8,397	2738
1987	1793	252	9,185	1950
1988	1955	90	10,021	1114
1989	2104	<59>	10,797	338
1990	2245	<200>	11,530	<395>
1991	2348	<303>	12,059	<924>
1992	2464	<419>	12,738	<1603>
1993	2605	<560>	13,405	<2270>
1994	2759	<714>	14,149	<3014>
1995	2924	<995>	14,950	<4577>
1996	3098	<1169>	15,795	<5422>
1997	3268	<1339>	16,621	<6248>
1998	3450	<1521>	17,503	<7130>

Source: Ref. 9. 20% reserve margin added by WCC. Net requirements computed using Table B-4. Does not include contingent sales 1982-1988.

Note: < > means requirements exceed supply.

Table B-44. SUMMARY OF "POTENTIAL INDUSTRIAL GROWTH" SCENARIO

Year	Peak Requirements (MW)	Net Surplus/ Deficit Peak Requirements (MW)	Energy Requirements (GWh)	Net Surplus/ Deficit Energy Requirements (GWh
1981	1276	<45>	6,599	<638>
1982	1339	316	7,160	1,549
1983	1417	368	7,696	1,822
1984	1664	443	8,815	1,511
1985	1790	317	9,276	1,050
1986	2395	<350>	12,550	<1,415>
1987	2520	<475>	13,227	<2,092>
1988	2713	<668>	14,289	<3,154>
1989	2824	<779>	14,899	<3,764>
1990	3217	<1172>	17,045	<5,910>
1991	3284	<1239>	17,395	<6,260>
1992	3355	<1310>	17,880	<6,755>
1993	3461	<1416>	18,361	<7,226>
1994	3558	<1513>	18,837	<7,702>
1995	3671	<1742>	19,395	<9,022>
1996	3798	<1869>	20,023	<9,650>
1997	3923	<1994>	20,648	<10,275>
1998	4058	<2129>	21,327	<10,954>

Source: Ref. 9. 20% minimum reserve added by WCC. Net requirements computed using Table B-4. Does not include contingent sales 1982-1988.

Note: < > means requirements exceed supplies.

SUMMARY

As the preceding discussion indicates, PNM used a complex process when preparing its demand forecasts for NMGS. Three different forecasting models were used (not to mention the models used in preparing the input variable forecasts). Five separate demand scenarios were prepared, covering a wide range of potential futures. Figure B-1 diagrams the relationships between the various models and scenarios.

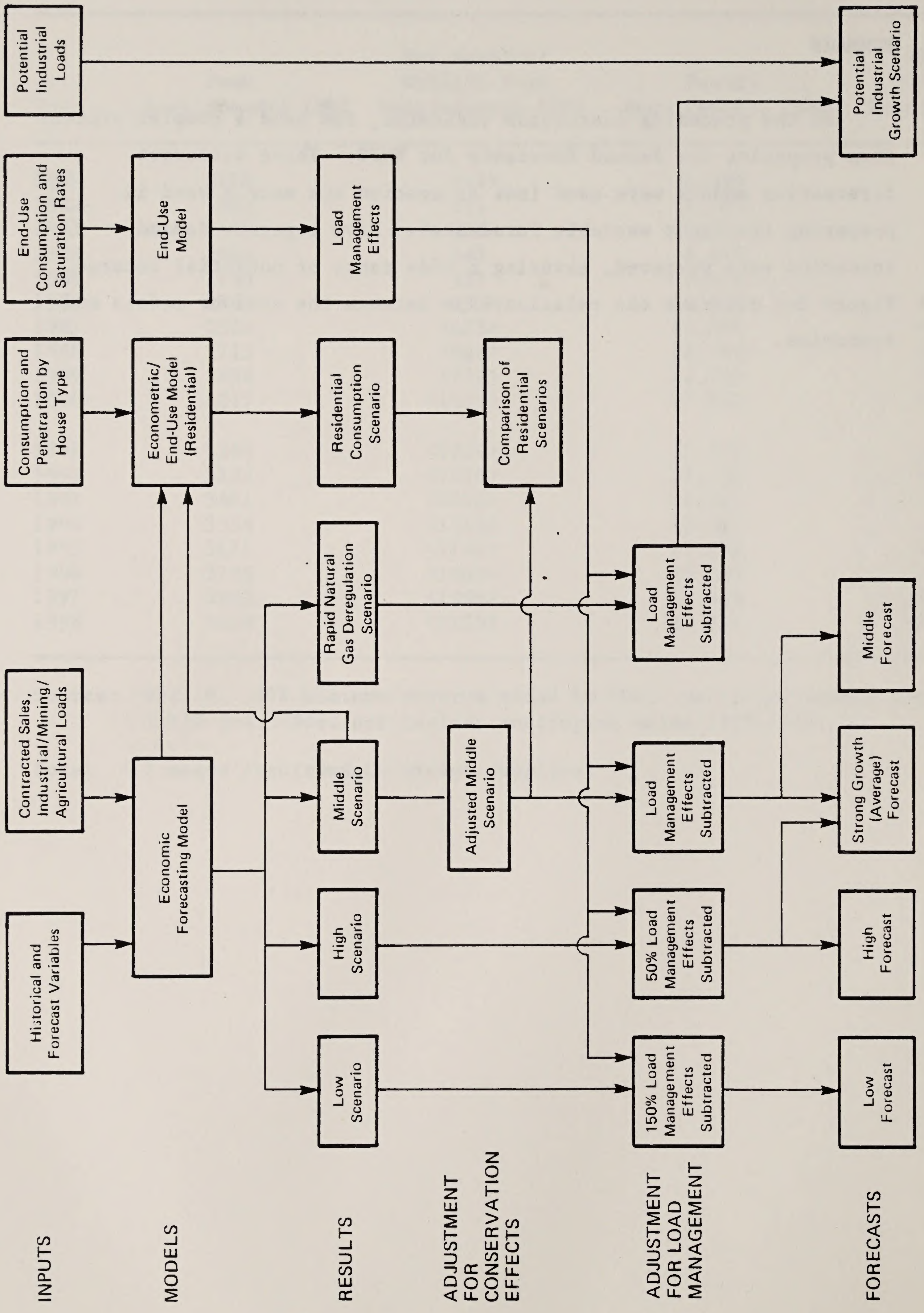
INPUTS
MODELS
RESULTS
ADJUSTMENT FOR CONSERVATION EFFECTS
ADJUSTMENT FOR LOAD MANAGEMENT
FORECASTS
Historical and Forecast Variables
Contracted Sales, Industrial/Mining/Agricultural Loads
Consumption and Penetration by House Type
End-Use Consumption and Saturation Rates
Potential Industrial Loads
Economic Forecasting Model
Econometric/End-Use Model (Residential)
End-Use Model
Low Scenario
High Scenario
Middle Scenario
Rapid Natural Gas Deregulation Scenario
Residential Consumption Scenario
Load Management Effects
Adjusted Middle Scenario
Comparison of Residential Scenarios
150% Load Management Effects Subtracted
50% Load Management Effects Subtracted
Load Management Effects Subtracted
Load Management Effects Subtracted
Low Forecast
High Forecast
Strong Growth (Average) Forecast
Middle Forecast
Potential Industrial Growth Scenario

Figure B-1. OUTLINE OF PNM FORECASTING PROCESS FOR NMGS

B.3.1 PRINCIPAL FINDINGS

1. PNM has had high historical growth during the last decade. PNM's forecasts for the period 1981-1988 project total rates of growth lower than this historical rate. In the decade of the 1970s, PNM and NME experienced a combined average compound growth in total electrical sales of 8.2 percent/year. Simple trend extrapolation would assume that this rate of growth would continue into the future. If this were to occur, there would be a need for capacity greater than NMGS on its most accelerated schedule. All of PNM's forecasts project a growth rate less than 8.2 percent (from 4.1 to 6.6 percent for GWh requirements growth from 1981 to 1998). However, much of the growth in the 1970s results from increased sales for resale. If PNM service area load growth alone is looked at, the growth rate is 5.6 percent per year in the 1970s, and ranges from 5.5 to 8.5 percent from 1981 to 1998. Only the low scenario is lower than historical growth in this case. In the 1980s, growth rates for PNM in isolation average from 7.5 to 9.7 percent per year. Thus, all forecast scenarios are higher than historical growth during the 1980s.

2. PNM's forecasts project the need for mid-range to baseload capacity during the 1990s. The maximum overall capacity factor desirable for PNM's generation can be estimated by comparing peak demand to total demand for the projected need. The formula for this comparison is:

load factor = (total demand/peak demand) x 8760 hr/yr

This computation indicates that the overall capacity factor requirements in 1998 will be 70.4, 57.3, and 51.8 percent in the low, middle and high scenarios, respectively (computed from Tables B-5 and B-6). Thus there is a strong indication that baseload capacity (generally about 65-75 percent capacity factor) is needed in the low scenario and an indication that a combination of baseload and mid-range capacity (about 30-50 percent capacity factor) is needed in the middle and high scenarios.

3. PNM's forecasts assume a continuing highly favorable economic climate in New Mexico. PNM's forecast scenarios use input variables that implicitly contain the assumption that a relatively good economic climate in New Mexico will continue through the next two decades. For example, real per capita personal income is forecast to increase 2.4-2.9 percent per year, population is forecast to increase 2.0-3.3 percent per year and industrial employment is forecast to increase 4.1-6.5 percent per year. These rates are generally higher than the rates in the 1970s. If slow economic growth or recessions were to occur or if trends causing migration to the Southwest were to change, electrical demand growth could be lower than the low scenario. On the other hand, a very strong economic climate or new types of electrical demand (e.g., electric cars) could result in demands higher than the high scenario.

4. PNM's low scenario projects that existing and planned capacity will not be sufficient by the mid 1990s. In PNM's low scenario, surplus capacity will be available through 1993 with 56 MW needed in 1994 to maintain a 20 percent reserve margin and 403 MW needed by 1998. This indicates that the first unit of NMGS (500 MW) would not be needed until 1994 at the earliest. If interim purchases of power

could be arranged, the first unit could be delayed somewhat. Additional units would not be needed until after 1998.

5. PNM's middle scenario projects that existing and planned capacity will not be sufficient by the early 1990s. In PNM's middle scenario, 37 MW would be needed in 1990 to maintain a 20 percent reserve margin; 620 MW would be needed by 1995, and 950 MW by 1998. Thus the first 500 MW unit of NMGS could be brought on line between 1990 and 1995, with sales or purchases of power used to keep a 20 percent reserve. A second unit could be brought on line between 1995 and 1998.

6. PNM's high and "industrial loads" scenarios project that existing and planned capacity will not be sufficient by the mid to late 1980s. In PNM's high scenario, 20 MW of additional capacity would be needed by 1988 to retain a 20 percent reserve margin; 498 MW would be needed by 1991, and 2091 MW would be needed by 1998. Thus the first unit of NMGS could be brought on line between 1988 and 1991, with other units following rapidly and all four on line by 1998. In PNM's industrial loads scenario, 350 MW would be needed in 1986 to retain a 20 percent reserve margin. Since NMGS could not be on line by this time, outside purchases of power would be required.

7. The proposed merger between PNM and NME would have little effect on the need for NMGS. Although the boards of both PNM and NME have indicated their desire for a merger, this action has been denied by the New Mexico PSC. This denial is being appealed. Even if the appeal is rejected, it is still possible that PNM could sell power to NME. At present PNM and NME are not electrically interconnected, and are in different coordinating councils: PNM is in the Western Systems Coordinating Council (WSCC) and NME belongs to the Southwest Power Pool (SWPP). Thus, to become interconnected, NME would have to

withdraw from SWPP or the interconnection would have to be done with special DC transmission lines (to avoid synchronization problems).

In any event, the results of the needs analysis will not be significantly affected by inclusion or deletion of NME. NME's projected capacity and demand are similar, with a planned capacity of 184 MW in 1998 versus a forecasted demand of 228 MW (including 20 percent minimum reserve margin).

8. PNM's estimates of future natural gas costs strongly influence model results. In all of its forecasting scenarios, PNM has assumed large increases in the price of natural gas over the next 20 years. Increases are projected to be particularly large in the mid 1980s when deregulation is expected to occur. There are wide differences of opinion about whether these increases will occur. If they do not, then PNM's actual demand could be significantly lower than the forecast scenarios. This is because the inferred shifts of usage between natural gas and electricity would not occur if the price of natural gas were to stay much less than the price of electricity (as it is now). Table B-45 shows that projections made in 1981 were relatively consistent in their estimates of natural gas prices. However, recently the argument has been made that natural gas prices will not increase dramatically in the future [40].

B.3.2 TECHNICAL COMMENTS ON FORECASTING METHODOLOGY

In general PNM appears to have used a satisfactory process to address demand forecasting. The methods used by PNM are generally as sophisticated as those used by utilities of comparable size. There are some state-of-the-art methods being considered by PNM which have not been implemented at this time.

Table B-45. NATURAL GAS PRICE PROJECTIONS (1980 Dollars per MMBtu)

Source	1980-1981	1985	1990	1995	2000
Parker [30]	2.00	3.00	6.25	8.00	11.00
CEC [36][a]	3.45	4.80	6.79	8.33	9.30
GRI [37]	4.00				8.00
Wharton [38][b]	2.00		6.6		
DRI [39][c]	3.50		6.6		

[a] Table 4, p. 19.

[b] Wellhead prices, discounted to 1980 dollars by WCC.

[c] Residential prices, discounted to 1980 dollars by WCC.

As with any forecast, PNM's forecast could be improved with more time and effort. Some of the comments below relate to potential improved approaches. These improvements would provide somewhat more confidence in the forecast results. However, the BLM does not have an opinion as to how the overall forecast would change if the suggested improvements were made.

Regression Models Assume That the Relationships Between the Variables Will Remain Unchanged

Based on historical data, the regression equations developed by PNM indicate a strong relationship between natural gas prices and electrical consumption. PNM has assumed that this relationship will continue as the price of natural gas increases. While it is not clear that this assumption is valid, it is also not obvious how the model could be adjusted to account for changes in the relationship between natural gas prices and electrical consumption.

PNM has attempted to adjust its model for changes in the relationship between electrical consumption and other variables. The coefficient in the regression equations for the variable "per capita personal income" was reduced as a way intended to capture an anticipated change in the relationship of electrical demands and income due to increased conservation. This is not appropriate from a theoretical viewpoint, since the model will have a poorer fit with historical data after such adjustments. A more straightforward approach to capturing conservation effects would be to use the original model and then subtract an estimate of the amount of savings that will occur due to conservation. This allows identification of the exact types and amounts of conservation included, something that is not possible by adjusting regression parameters.

PNM adjusted certain values of its electrical price variables. Specifically, when the price is projected to go down, the amount of the decrease is reduced. Note that, since price decreases have been made smaller but price increases have been kept the same, the total price of electricity will be higher in all years and not just in the years where adjustments have been made.

PNM also adjusted the values of the population and employment input variables by combining BBER's 1980 and 1981 forecasts using a weighted average. It appears that PNM felt that the 1981 values were too high, however, there is no justification given for selecting the particular method of revising these forecasts chosen.

Note that all of the adjustments described above result in lower forecasts.

Inferring levels of conservation by comparing the results of the adjusted econometric model and the econometric/end-use model may not be technically correct. The results of the adjusted econometric model (residential sector) and the econometric/end-use model of the residential sector are very similar. PNM uses this fact to infer that the adjusted econometric model is capturing some of the conservation and solar adoption impacts modeled in the econometric/end-use model. However, this conclusion is not warranted, since the two models reach their forecasts through different methods and assumptions. It is also not correct to assume that because the residential models achieve similar results, the adjusted commercial econometric model would achieve results similar to those of an econometric/end-use commercial model. This is particularly true since the size of the adjustments made to the two sectors in the econometric model is different (e.g., a 25 percent reduction in the personal income variable in residential versus 4 percent in commercial). In order to be able to make this assumption, some type of cause-and-effect relationship should be shown between the models. This relationship has not been demonstrated.

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